AUSTIN ENERGY 2016 MAY 31 AM 8:55

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| **AUSTIN ENERGY'S TARIFF PACKAGE: 2015 COST OF SERVICE STUDY AND PROPOSAL TO CHANGE BASE ELECTRIC RATES** | § § § § | **BEFORE THE CITY OF AUSTIN IMPARTIAL HEARING EXAMINER** |

**DATA FOUNDRY, INC.'S RESPONSE TO IHE MEMORANDUM NO. 17 <u>CONCERNING OFFICIAL NOTICE</u>**

Intervenor Data Foundry, Inc. ("Data Foundry") provides this response to the request in IHE Memorandum No. 17 that Data Foundry provide more information regarding official notice of certain materials. Specifically, IHE Memorandum No. 17, page 10 states:

> The Impartial Hearing Examiner requests that Data Foundry identify with more specificity what precisely and perhaps which edition of the "NARUC Manual" Data Foundry seeks official notice of, as well as which of the PUCT's Substantive Rules Data Foundry wants officially noticed.

Data Foundry's goal is to be able to use some or all of the identified material during the evidentiary hearing,[1] and then – whether mentioned in the hearing or not – during briefing and for purposes of the ultimate decision. Data Foundry will heavily rely on some of this material during the briefing phase. Data Foundry can, however, materially reduce its need to actually use this material during the evidentiary hearing if Data Foundry receives assurances that it will be independently able to cite to and quote from any and all of it in its briefs and that the IHE will be able to also use the material for purposes of the Final Recommendation to the extent he believes it is helpful, even if it is not the subject of any cross-examination.

This is a "evidence" issue. The question is whether the PUC Substantive Rules and the NARUC Electric Cost Allocation Model must be included in the evidentiary record in some fashion as a precondition to use during cross-examination and, separately, in the briefs. Since Data Foundry will be asking the IHE to take this material into account and substantively rely on it for purposes of the Final Recommendation, Data Foundry wants to be sure that – if necessary – it is included in the record in some fashion so the IHE can do so if he finds it useful.

[1] As explained below, Counsel for Data Foundry and Austin Energy ("AE") conferred after the prehearing conference, but the other parties have not weighed in.

**Data Foundry's Response to IHE Memorandum No. 17 Concerning Official Notice**

1. PUC Substantive Rules. Data Foundry's continued preparation has led to the conclusion that Data Foundry likely will not be using any PUC Substantive rules during cross-examination. Data Foundry reserves the right, however, to cite to those rules during the briefing stage, and the IHE may also find that recourse to them is necessary or appropriate for purposes of the Final Recommendation. Data Foundry notes that state agency rules do not stand in the same stead as state legislation. Unlike actual statutes agency rules are typically not automatically available for use without some evidentiary foundation. That is why they are specifically addressed in Tex.Rs.Evid. 204.

This issue is not unique to Data Foundry. Other parties even more heavily rely on several PUC rules in their presentations. For this reason Data Foundry will defer to any consensus about how this matter should be resolved.

2. NARUC Electric Utility Cost Allocation Manual. Data Foundry does still presently intend to use some or all of the below-identified portions of the January 1992 NARUC Electric Utility Cost Allocation Manual[2] during cross-examination, and may offer some or all of this material as part of one or more substantive or demonstrative exhibits.[3] Data Foundry also gives notice that it intends to make extensive references to and provide quotations from this material during briefing, even if not used during cross-examination. Data Foundry will also ask the IHE to consider and rely on some of this content as part of his Final Recommendation. To the extent there are evidentiary concerns about use during the evidentiary hearing, briefing inclusion and/or IHE use they must be resolved before the evidence is closed.

Specifically, Data Foundry provides notice that it may question AE and/or Intervenor witnesses about the discussion contained in the attached portions of the

[2] The Manual is available for download in its entirety at http://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD.

[3] Data Foundry will not be using wide swaths of the identified material during the hearing, but has not made a final determination regarding what specific parts it will use. Counsel will endeavor to limit hearing time use of the attached material to only that which is essential to prosecution of Data Foundry's cross-examination. Data Foundry's hearing time requirements can be materially reduced if Data Foundry is able to freely cite to and quote from any of the attached material in brief with the understanding that the IHE will be able to rely on and use it – even if never mentioned during the evidentiary hearing – to the extent he believes the material is helpful to his Final Recommendation.

Manual.[4] Data Foundry also provides notice that it will be including far more of the content attached hereto in its briefing, and will be asking the IHE to consider and substantively rely on that content for purposes of the Final Recommendation.

Counsel for Data Foundry and AE have conferred. AE counsel has indicated that while he does not take a position on whether the Manual is judicially congizable he will not object to use of the Manual. AE counsel also stated that the Manual would not have to be admitted as an exhibit if it is used during Data Foundry's cross-examination of AE witnesses. Other parties have not provided any input on the issue.

Data Foundry believes that the Manual is judicially cognizable under Tex.Rs.Evid. 201(b). To the extent there are hearsay concerns Data Foundry would not be seeking to have any witness concur with the truth of the matter asserted in the material. Instead the point would be to show that NARUC has adopted the principles indicated in the Manual and has provided the analysis contained therein. Data Foundry might then ask the witness for his or her thoughts concerning those principles and/or the NARUC analysis. The material is not hearsay under Rule 801(d)(2) in that context. Even if it is hearsay the Manual is an exception to the hearsay exclusion under Tex.Rs.Evid. 803(18).[5] In addition, much of the AE and Intervenor testimony is opinion testimony, and thus necessarily proffered through an alleged "expert." Therefore cross-examination of the "expert" using the Manual would be appropriate under R. 705(a) since the issue is related to potential impeachment of the "expert's" underlying "facts or data."

Data Foundry's preference for official notice flows from the fact that Rule 803's providing that learned text (and religious records) are exceptions to the hearsay exclusion go on to indicate that the text must be read into the record and cannot be offered as an exhibit. That would consume a lot of time, and hopefully it can be avoided. Data Foundry would also prefer to not have to do all of this in the context of "*voire dire*" – especially given that this is not a jury case. *See* R. 705(b).

[4] Data Foundry will not object to any other party's exercise of the right of optional completeness.

[5] Given the zeal with which many embrace ratemaking concepts one could perhaps claim R. 803(11) also applies.

**<u>Data Foundry's Response to IHE Memorandum No. 17 Concerning Official Notice</u>**

Data Foundry is trying to find a way to minimize the amount of hearing time required to ensure that recourse to the Manual is available for any and all purposes. Therefore, Data Foundry requests that that the issue of recourse to the contents of the Manual during the evidentiary hearing, in briefing and in the Final Recommendation be resolved out the outset so everyone knows how to proceed.

Data Foundry trusts that the foregoing adequately responds to the request in IHE Memorandum No. 17.

Respectfully submitted,

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May 28, 2016

**CERTIFICATE OF SERVICE**

I, W. Scott McCollough, certify that I have served a copy of this filing on all parties listed on the Service List for this proceeding as it exists on the date this document is filed, using the email address provided for the party representative.

__________________________

W. Scott McCollough

# ELECTRIC UTILITY
# COST ALLOCATION MANUAL

**January, 1992**

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS

1101 Vermont Avenue NW
Washington, D.C. 20005
USA
**Tel: (202) 898-2200**
**Fax: (202) 898-2213**
**www.naruc.org**

$25.00

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# CONTENTS

In the electric industry, work is termed energy; power is termed capacity or capability in discussions of generating plants, and demand in discussions of customer usage.

The basic unit in electricity is the watt, most familiar as the rating on light bulbs and appliances. A 100 watt bulb burning constantly for an hour would use 100 watt-hours of electricity. Thus, watts are a measure of capacity while watt-hours add the dimension of the time period during which the capacity is used. Since the watt is a very small unit of measurement (746 watts equal 1 horsepower), consumer bills are measured in kilowatt-hours (thousands of watt hours) and utility system generation is reported in megawatt-hours (millions of watt hours).

## B. Generation

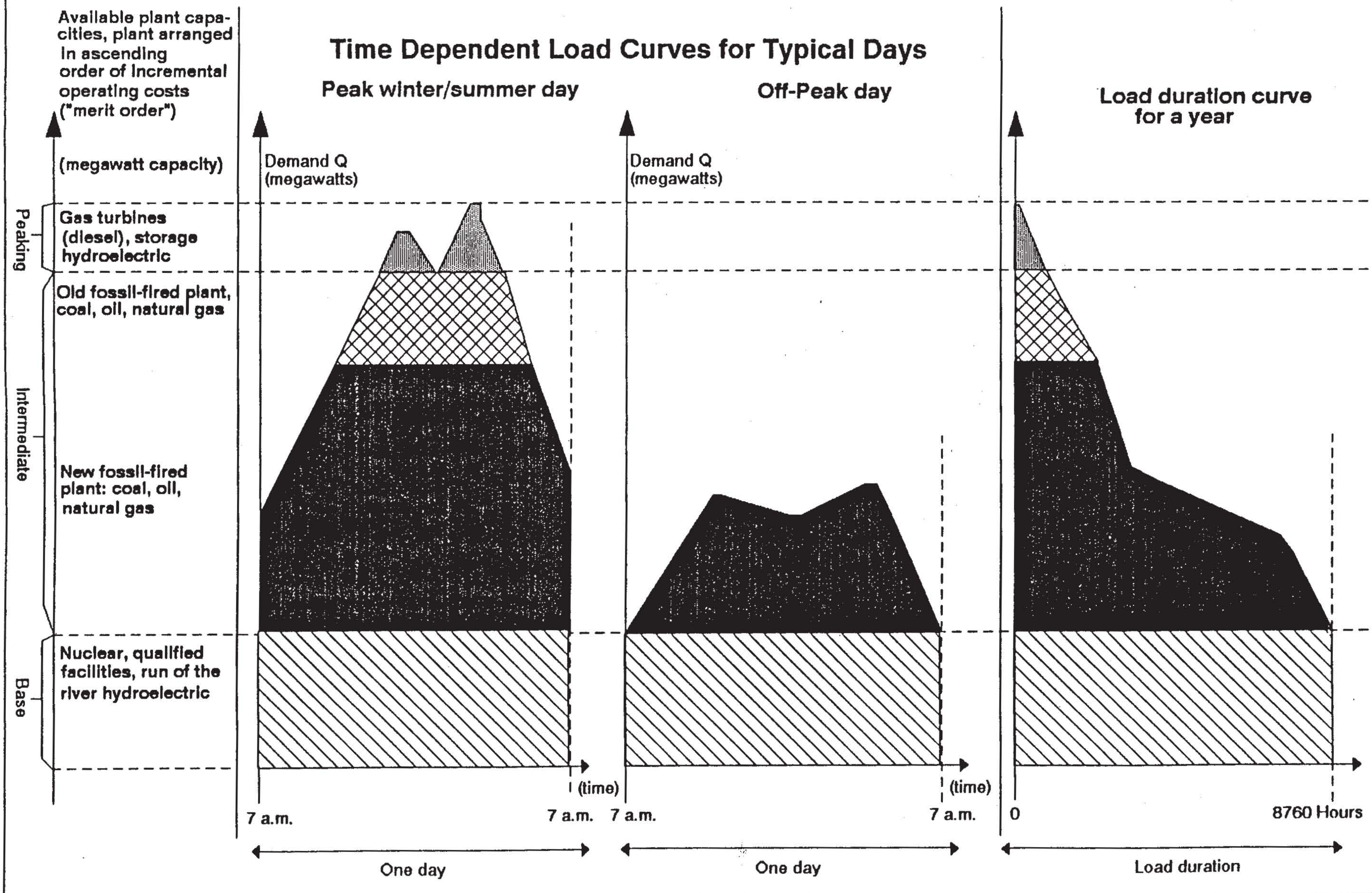
The demand for power on an electric system varies with time, with variations occurring for any given utility in a fairly predictable pattern during the hours of a day and the seasons of a year (see Figure 1-1). A graph that plots hours of the day against demand on the system will typically show low usage during the night hours, which rises to one or more peaks during the day hours as customers turn on their machinery (and heat or cool), and then gradually falls during the late evening hours. Similarly, the graph of a utility's annual demand will typically demonstrate the lower demand on the system in the spring and fall with greater usage exhibited in the winter and/or summer reflecting electric heat and air conditioning loads.

Such time differentiated graphs can be translated into load duration curves in which demand, rather than plotted against hours of the day or days of the year, is plotted against the number of hours of the year (up to all 8760) during which any particular level of demand occurs. The shape of the load duration curve over the year in large measure determines the utility planner's choice of generating plant needed to satisfy customer demand. The challenge to the system planner is to provide sufficient generating capacity to satisfy the peak demand, while recognizing that much of that plant will not be needed for a large part of the day and year. As different types of generating units are marked by different operational and cost characteristics, the utility will attempt to build the types of units that provide it with the flexibility to match supply to demand for every hour at the lowest possible cost.

Utilities generate most power by burning fossil fuels (coal, oil and natural gas), employing nuclear technology, and running hydro-electric plants. In addition, they purchase power both from other utilities and from independent power producers whose facilities may include run-of-the-river hydro-electric, wood, municipal solid waste, wind, geothermal, tidal, or electricity cogenerated with some form of heat used in district heating or in a manufacturing process.

The utility system operators load (dispatch) and unload generating stations sequentially in order of operating costs as demand rises and falls on the system. Base load

## FIGURE 1-1
## LOAD DISPATCHING



plants are constructed to meet the utility's minimum demand by operating continually throughout the day and year. They cannot be loaded and unloaded easily, either because of their operating characteristics (for example, nuclear) or because of contractual or legal requirements (purchases from small power producers or run-of-the-river hydro-electric). They tend to have high fixed costs that can and must be spread over many hours of the year, and lower operating (primarily fuel) costs. At the other extreme, peaking plants are constructed to satisfy the demand that may occur only for a few hours of the year. These plants must be easily loaded and unloaded onto the system and, since the hours of their operation are limited, must have low capital costs. Generally, they also have high fuel costs (e.g., gas turbines) although hydro-electric stations with some reservoir capacity may also be constructed as peakers because of the ease of instantaneous operation. Intermediate plants, fossil fuel stations burning coal, oil and natural gas, are dispatched less frequently than base load and more often than peakers. Dispatch of particular stations will vary according to relative fuel costs: in periods of particularly low oil prices, for example, oil-fired stations may operate as baseload rather than intermediate plants.

In recent years it has become apparent that utilities have the option of influencing their demand curves as well as varying their sources of supply. Thus, a utility with base load capacity but a rising peak demand may be able to shift some of its peak load to off-peak hours, to make better use of its base load facilities, rather than building additional peaking units.

## C. Transmission

A utility's transmission system consists of highly integrated bulk power supply facilities, high voltage power lines and substations that transport power from the point of origin (either its own generation or delivery points from other utilities) to load centers (either in its own franchise territory or for delivery to other utilities). The transmission function is generally concluded at the high voltage side of a distribution substation owned by the utility or at points where the ownership of bulk power supply facilities changes.

In general, the transmission system is comprised of four types of subsystems that operate together. The backbone and inter-tie transmission facilities are the network of high voltage facilities through which a utility's major production sources, both on and off its system, are integrated. Generation step-up facilities are the substations through which power is transformed from a utility's generation voltages to its various transmission voltages. Subtransmission plant encompasses those lower voltage facilities on some utilities' systems whose function is to transfer electric energy from convenient points on a utility's backbone system to its distribution system. Radial transmission facilities are those that are not networked with other transmission lines but are used to serve specific loads directly.

# CHAPTER 2

## OVERVIEW OF COST OF SERVICE STUDIES AND COST ALLOCATION

This chapter presents an overview of cost of service studies and cost allocation theory. It first introduces the role of cost of service studies in the regulatory process. Next, it summarizes the theory and methodologies of cost studies, with a comparison of accounting-based (embedded) cost methodologies and marginal cost methodologies. Finally, it introduces and briefly discusses the three major steps in the cost allocation process: the "functionalization" of investments and expenses, cost "classification", and the "allocation" of costs among customer classes.

### I. COST OF SERVICE STUDIES IN THE REGULATORY PROCESS

Cost of service studies are among the basic tools of ratemaking. While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates.

The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers, and segments of the utility's business. Cost studies are therefore used by regulators for the following purposes:

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate costs of individual types of service based on the costs each service requires the utility to expend.
- To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets.

- To separate costs between different regulatory jurisdictions.

Generically, the prime purpose of cost of service studies is to aid in the design of rates. The development of rates for a utility may be divided into four basic steps:

- Development of the test period total utility revenue requirement - The total revenue requirement is the level of revenue to be collected from all sources. This subject will be addressed in detail in Chapter 3.

- Calculation of the test period revenue requirement to be recovered through rates - This is simply the total revenue requirement of the utility from all sources less the amount from sources other than rates.

- The cost allocation procedure - The total revenue requirement of the utility is attributed to the various classes of customers in a fashion that reflects the cost of providing utility services to each class. The cost allocation process consists of three major parts: functionalization of costs, classification of costs, and allocation of costs among customer classes.

- Design of rates - Regulators design rates, the prices charged to customer classes, using the costs incurred by each class as a major determinant. Other non-cost attributes considered by regulators in designing rates include revenue-related considerations of effectiveness in yielding total revenue requirements, revenue stability for the company and rate continuity for the customer, as well as such practical criteria as simplicity and public acceptance.

## II. THEORY AND METHODOLOGIES

Historically, regulation concerned itself with the overall level of a company's revenues and earnings and left the design of rates to the discretion of the utility. To the extent that utility managements justified their rate structures on cost, rather than rationales of value of service or "what the market will bear", they defined cost in engineering and accounting terms. Utilities developed cost studies that were based on monies actually spent (embedded) for plant and operating expenses and divided those costs (fully allocated or distributed them) among the classes of customers according to principles of cost causation. The task for the analyst was to allocate, among customers, the costs identified in the test year for which the revenue requirement had been calculated.

Through the years, the industry and its regulators have witnessed a gradual evolution of the concepts for allocation. Since generating units and transmission lines are sized according to the peak demand consumed, the individual contribution to peak demand came to be considered the appropriate factor for the allocation of the costs of those facilities. Costs incurred to supply energy such as fuel were rationalized to be allocatable by usage. Costs that vary by the number of customers and not their consumption were allocated by customer. While subsequent analysis has complicated the assignment of particular costs to various categories, cost allocation has generally evolved into three cost classifications: demand, energy and customer.

By the 1970's, the economic environment had changed for the electric utilities. In the new era of general inflation, high energy and construction costs, and competition, rates based on pre-inflationary historical costs led to poor price signals for customers, inefficient uses of resources for society, and repeated revenue deficiencies for the companies. Regulators and utilities began to inquire whether the principles of marginal cost were the appropriate reference for regulated utility rate structures in the United States. Such concepts had long been the theoretical economic framework for the analysis of competitive markets, and since the 1950's, the basis of utility rates in England and France.

Marginal cost theory is derived from the neo-classical economics of the nineteenth century which states that in a perfectly competitive equilibrium, the amount consumers are willing to pay for the last unit of a good or service, equals the cost of producing the last unit, i.e., its marginal cost. As a result, the amount customers are willing to pay for a good equals the value of the resources required to produce it, and society achieves the optimal level of output for any particular good or service. In a competitive market, this equilibrium is achieved as each firm expands its output until its marginal cost equals the price established by the forces of supply and demand. For the utility monopoly, the regulator attempts to achieve the same allocative efficiency by accepting the level of service demanded by customers (the utility's obligation to serve) as the given, and setting price (or rates) equal to the utility's marginal cost for that level of output. The analyst defines the cost as the change in cost due to the production of one unit more or less of the product, and various approaches have been advanced to measure the utility's marginal cost.

A deficiency of the marginal approach for ratemaking purposes is that marginal cost-based prices will yield the utility's allowed revenue requirement based on embedded costs only by rare coincidence. Since regulatory agencies are bound not to let the utility over-earn or under-earn, revenues from rates must be reconciled to the allowed revenue requirement. As the rates are reconciled to the revenue reqirements and prices diverge from marginal cost, the sought after marginal cost price signals may not be obtained. When prices do not exactly equal marginal cost there is no formal proof that the economic efficiency predicted by theory is achieved. Advocates of marginal cost pricing believe that approximations to marginal cost pricing must contribute to efficient resource allocation, although to an unspecifiable degree. Supporters of embedded cost pricing believe that the greater precision, verifiability and general simplicity of embedded cost methods outweigh any of the hoped for efficiency benefits of imperfect approximations to marginal cost pricing. This problem and various proposed solutions are addressed in Chapter 10.

It is important to note that the difference between an embedded cost of service study and a marginal cost of service study lies in their different concepts of cost. The embedded cost study uses the accounting costs on the company's books during the test year as the basis for the study. In contrast, the marginal cost study estimates the resource costs of the utility in providing the last unit of production. Once "cost" is determined, the procedures for allocating cost among services, jurisdictions and customers are largely the same. Thus, the practical and theoretical debates in marginal cost studies tend to center around the development of costs, while the debates in embedded cost studies focus on how the cost taken directly from the company's books should be divided among customers.

## III. EMBEDDED AND MARGINAL COST STUDY ISSUES

There are three subjects of particular interest in the development of cost studies: treatment of joint and common costs, time-differentiation of rates, and incorporation of future costs. The following discussion will briefly address how the two types of studies deal with those issues.

### A. Joint and Common Costs

Joint costs occur when the provision of one service is an automatic by-product of the production of another service. Common costs are incurred when an entity produces several services using the same facilities or inputs. The classic example of joint costs are beef and hides where it is not possible to allocate separate costs of raising cattle to the individual product. In the electric industry, the most common occurrence of joint costs is the time jointness of the costs of production where the capacity installed to serve peak demands is also available to serve demands at other times of the day or year. Overhead expenses such as the president's salary or the accounting and legal expenses are examples of costs that are common to all of the separate services offered by the utility.

In an embedded cost study the joint and common costs identified in the test year are allocated either on the basis of the overall ratios of those costs that have been directly assigned, or by a series of allocators that best reflect cost causation principles such as labor, wages or plant ratios, or by a detailed analysis of each account to determine beneficiality. The classification and treatment of the joint and common costs requires considerable judgment in an embedded cost study. (See Chapters 4 through 8 for a more detailed discussion).

In a marginal cost study, the variation of those common costs that vary with production is incorporated into the study through regression techniques and becomes a multiplier to the marginal cost per kilowatt or kilowatt-hour. There are fewer joint and common costs in marginal cost studies than in embedded because many of the common costs do not vary with changes in production. The presence of joint and common costs, both variable and non-variable, contributes to the inequality between the totals obtained from a marginal cost study and the revenue requirement based on the embedded test year costs.

## B. Time Differentiation of Rates

Most time differentiation of rates stems from the recognition that costs vary by time. It is a popular misconception that time differentiated rates are a unique feature of marginal cost studies. To the contrary, both embedded and marginal cost studies can be designed to recognize cost variations by time period. It is true that marginal cost studies are designed to calculate the energy and capacity costs attributable to operating the last (marginal) unit of production during every hour of the year. The hours can then be grouped into peak, off-peak and shoulder periods for costing and pricing purposes. However, in embedded studies, the baseload, intermediate and peak periods can be identified, and different configurations of production plants and their associated energy costs, can be assigned to each period. (See Chapter 4.) Thus, the primary difference between the two types of studies in regard to the calculation of time differentiated rates is that the costs fall naturally out of a marginal cost study while embedded cost analysts are required to perform a separate costing step before allocating costs to the customer classes.

## C. Future Costs

In most cost studies submitted to regulatory commissions, the accounting costs in embedded cost studies reflect the cost incurred in providing a given level of service over some time period in the past. Optimally, the utility's cost study and test year for revenue requirement purposes will be based on the most recent twelve months for which data are available, although regulators are often faced with the difficulties of stale test years. To the extent that the price of inputs, technology, and managerial and technical efficiency cause the cost of providing service in the past to differ from the cost of service in the future, rates based on historic test years will over- or under-collect during the years the rates are in effect. Within the context of embedded studies, solutions to the need to incorporate future costs include recognition of known and measurable changes to the test year costs, step increases between rate cases, fuel adjustment mechanisms to give immediate recognition to variations in fuel costs and the use of a forward-looking test year for the cost study. This last is the most comprehensive response to the need to reflect future costs within an embedded study. However, it has the disadvantage of relying on estimated costs rather than costs that are subject to verification and audit. Thus, in the eyes of many regulators, an embedded study based on a future test year loses one of the prime advantages it has over marginal cost studies.

In contrast to the standard embedded cost study, marginal costs by definition, are future costs. Marginal cost studies estimate either the short-run marginal costs, in which plant, equipment and organizational skills are fixed, but labor, materials and supplies can be varied to satisfy the change in production, or the long-run marginal costs, in which all inputs including production capacity can be adjusted. As a matter of practicality, marginal cost studies usually adopt an intermediate period tied to the planning horizon of the utility.

## IV. SOURCES OF DATA

While the data for cost studies are generally provided by the utility company, the documents that are relevant depends on the type of cost study being performed. Embedded cost studies rely on the company's historical records or projections of these records, whose accuracy can be audited and verified either at the time of filing or at the end of the period projected. Marginal cost studies use the company's planning documents.

### A. Data for Embedded Cost Studies

Where a cost of service study is made in conjunction with a rate case proceeding, the costs that are distributed to the various classes of service should be the costs used in determining the utility's overall revenue requirement. The principal items of historical information required to develop cost allocations based on accounting costs are plant investment data, including detailed property records, balance sheets, information on operating expenses and on performance of generating units, load research (information on KWH consumption and the patterns of that consumption) and system maps. These costs are contained in the books and records maintained by the company, and are proformed to recognize known and measurable changes. The utility files projected revenues, investment and costs for all accounts in cost studies using projected test years.

Electric utilities generally are required by law to keep their records according to the Uniform System of Accounts (USOA) as prescribed by the Federal Energy Regulatory Commission in the Code of Federal Regulations CFR Title 18, Subchapter C, Part 101. This code sets the guidelines for booking assets, liabilities, incomes and expenses into each account. Major categories of costs are listed as follows:

| | |
|---|---|
| 100 Series | Assets and other debits |
| 200 Series | Liabilities and other credits |
| 300 Series | Electric plant accounts |
| 400 Series | Income, and revenue accounts |
| 500 Series | Electric O&M expenses |

| | |
|---|---|
| 900 Series | Customer accounts, customer service and informational sales, and general and administrative expenses |

Series 600, 700 and 800 are not major categories of cost that are used for cost of service studies.

### B. Data for Marginal Cost Studies

The focus of marginal cost studies is on the estimated change in costs that results from providing an increment of service. The planning documents of the utility form the basis of the analysis, with those plans in turn being based on such tools and information as the output of the production costing model and the optimized generation planning model, the parameters established for reliability, stability and capability responsibility, and load and fuel forecasts. Costing for generation requires information on outage rates, operating and maintenance costs, alternate fuel capabilities and retirement schedules of existing plants, on the expected market for capacity purchases and sales, and on the capital and operating costs of alternate future generating units including their associated transmission.

Cost information on transmission, and to a lesser extent, distribution, is obtained from the utility's models of power flow analysis, with their associated transient stability programs, switching surge analyses and loss studies, and geographically specific load forecasts. Based on this information, the transmission and distribution planner will have developed a system expansion plan, the budget for which provides the cost data for the transmission and distribution portions of the marginal cost study.

Future customer and general and administrative costs, and in less sophisticated studies distribution costs as well, are not thought to vary significantly from the immediate historically incurred costs. Therefore, the sources of data for a marginal study will be the historic account data.

## V. THE COST ALLOCATION PROCESS

### A. Cost Functionalization

Once the relevant data on investment and operating costs are gathered and the relevance determined by the type of study and unique circumstances of each utility, the costs are then separated according to function. The typical functions used in an electric utility cost allocation study are:

- Production or purchased power

- Transmission
- Distribution
- Customer service and facilities
- Administrative and general

Each utility is a unique entity whose design has been dictated by the customer density, the age of the system, the customer mix, the terrain, the climate, the design preferences of management, the planning for the future, and the individual power companies that have merged to form the utility. Some utilities have generation plant, while others are only distribution systems. Therefore, the degree or complexity of functionalization will depend on the individual utility and the regulatory environment. The advent of computers encouraged a trend towards more detailed functionalization.

The assignment of costs to each function will generally follow the accounting categories defined in the USOA. At times, however, there will be exceptions. In such cases, the purpose of functionalization, not the accounting treatment, must drive the distribution of the functional costs for the cost study.

Following are descriptions of the typical cost functions used in an electric utility cost allocation study.

## 1. The Production Function

The production function consists of the costs associated with power generation and wholesale purchases. This includes the fossil fired, nuclear, hydro, solar, wind and other generating units. The costs associated with the purchase of power and its delivery to the bulk transmission system are also included.

## 2. The Transmission Function

The transmission function includes the assets and expenses associated with the high voltage system utilized for the bulk transmission of power to and from interconnected utilities and to the various regions or load centers of the utility's system.

## 3. The Distribution Function

The distribution function encompasses the radial distribution system that connects the customer to the transmission system. The distribution function is normally extensively subdivided in order to recognize the non-utilization of certain types of plant by particular customer classes. Since customers served at the primary distribution voltage do not utilize the plant necessary to transform the voltage to the secondary levels, the cost causation criteria requires that they not be allocated the cost associated with the secondary distribution system.

## 4. The Customer Service and Facilities Function

The customer service and facilities function includes the plant and expenses that are associated with providing the service drop and meter, meter reading, billing and collection, and customer information and services. These investments and expenses are generally considered to be made and incurred on a basis related to the number of customers (by class) and are, therefore, of a fixed overhead nature.

## 5. Administrative and General Function

The administrative and general function includes the management costs, administrative buildings, etc. that cannot be directly assigned to the other major cost functions. These costs may be functionalized by relating them to specific groups of costs or other characteristics of the major cost functions, and then allocated on the same basis as the other costs within the function.

## B. Classification of Costs

The next step is to separate the functionalized costs into classifications based on the components of utility service being provided. The three principal cost classifications for an electric utility are demand costs (costs that vary with the KW demand imposed by the customer), energy costs (costs that vary with the energy or KWH that the utility provides), and customer costs (costs that are directly related to the number of customers served).

After costs are functionalized into the primary functions, some can be identified as logically incurred to serve a particular customer or customer class. For example, a radial distribution line that serves only a particular customer may be assigned directly to that customer. Similarly, all the investment and expenses associated with luminaires and poles installed for street and private area lights are directly assigned to the lighting class(es). Segregation of these costs in a sense reverses the classification and allocation steps, as the costs are first allocated to the customer and subsequently classified as demand, energy or customer to determine how the customer is to be charged.

Typical cost classifications used in cost allocation studies are summarized below.

| Typical Cost Function | Typical Cost Classification |
| --- | --- |
| Production | Demand Related<br>Energy Related |
| Transmission | Demand Related<br>Energy Related |
| Distribution | Demand Related<br>Energy Related<br>Customer Related |
| Customer Service | Customer Related<br>Demand Related |

The typical cost classifications shown above reflect the following types of assumptions regarding cost causation for electric utilities.

## 1. Production

Costs that are based on the generating capacity of the plant, such as depreciation, debt service and return on investment, are demand-related costs. Other costs, such as cost of fuel and certain operation and maintenance expenses, are directly related to the quantity of energy produced. In addition, capital costs that reduce fuel costs may be classified as energy related rather than demand related. In the case of purchased power, demand charges are normally assumed to be demand related and energy charges are normally assumed to be energy related. Fuel inventory may be either demand or energy related.

## 2. Transmission and Subtransmission

The costs of transmission and subtransmission are generally considered fixed costs that do not vary with the quantity of energy transmitted. However, to the extent that transmission investment enables a utility to avoid line losses, some portion of transmission may be classified as energy related.

## 3. Distribution

The costs of electric distribution systems are affected primarily by demand and by the number of customers. As in transmission, it may be possible to identify some energy component of the cost.

### 4. Customer Service

Costs functionalized as customer service are related to the number of customers and, therefore, can be classified as customer costs as well.

In any of these functions, costs that are associated with service to a specific customer or customer class may be directly assigned. Although cost classifications are usually based on considerations similar to those listed above, there are numerous instances in which other methods of cost classification are considered. These various circumstances will be discussed in the chapters in Sections II and III.

## C. Allocation of Costs Among Customer Classes

After the costs have been functionalized and classified, the next step is to allocate them among the customer classes. To accomplish this, the customers served by the utility are separated into several groups based on the nature of the service provided and load characteristics. The three principal customer classes are residential, commercial, and industrial. It may be reasonable to subdivide the three classes based on characteristics such as size of load, the voltage level at which the customer is served and other service characteristics such as whether a residential customer is all-electric or not. Additional customer classes that may be established are street lighting, municipal, and agricultural.

Once the customer classes to be used in the cost allocation study have been designated, the functionalized and classified costs are allocated among the classes as follows:

- Demand-related costs - Allocated among the customer classes on the basis of demands (KW) imposed on the system during specific peak hours.
- Energy-related costs - Allocated among the customer classes on the basis of energy (KWH) which the system must supply to serve the customers.
- Customer-related costs - Allocated among the customer classes on the basis of the number of customers or the weighted number of customers. Normally, weighting the number of customers in the various classes is based on an analysis of the relative levels of customer-related costs (service lines, meters, meter reading, billing, etc.) per customer.

This manual only discusses the major costing methodologies. It recognizes that no single costing methodology will be superior to any other, and the choice of methodology will depend on the unique circumstances of each utilty. Individual costing methodologies are complex and have inspired numerous debates on application, assumptions and data. Further, the role of cost in ratemaking is itself not without controversy.

Dr. James Bonbright, whose Principles of Public Utility Rates is the classic examination of regulation and ratemaking, wrote:

> "Of all of the many problems of rate making that are bedeviled by unresolved disputes about issues of fairness, the one that deserves first rank for frustration is that concerned with the apportionment among different classes of consumers of the demand costs or capacity costs....Here, notions of 'fair apportionment' are almost sure to conflict with economists' convictions as to the relevant cost allocations. But these notions are themselves neither stable nor uniform, although they reveal a general tendency in favor of a fairly wide spreading out of the costs, as butter would be spread over bread in a well-made sandwich. Awareness of these unresolved conflicts about 'fair' cost apportionment has lead the British economist Professor W. Arthur Lewis to exclaim that, in rate determination, 'equity is the mother of confusion.'"

The purpose of this manual is to clarify, if not resolve, some of that confusion.

A utility is allowed the opportunity to earn a reasonable return on its investment that is prudent and dedicated to the public service. The return dollars a utility is entitled to collect is determined by multiplying the rate base by the rate of return, as follows:

$$R = RB \times r$$

Where:

| | |
|---|---|
| R | = Return |
| RB | = Rate base |
| r | = Rate of return (a percentage) |

Return is the amount of money a utility may earn over and above operating expenses, net of income taxes. Included in the return amount is interest on debt, dividends for preferred stock as well as the allowed earnings on common equity.

## C. Operating Expenses

Operating expenses are a group of expenses incurred in connection with a utility's operations and include: (1) operation and maintenance expenses; (2) depreciation expenses; (3) miscellaneous amortization expenses; (4) taxes other than income taxes; (5) income taxes; and (6) other operating revenues.

### 1. Operation and Maintenance Expenses

Operation and maintenance (O&M) expenses are the costs incurred by a utility in the course of supplying its services. O&M expenses include the costs of labor, maintenance, fuel, administrative expenses, regulatory commission expenses, materials and supplies, (to the extent such items are routine expenditures, not capital investments), purchased power and various other service-related expenses.

### 2. Depreciation Expense

Depreciation expense is the annual charge made against income to provide for distribution of the cost of plant over its estimated useful life. Among the factors considered in developing the annual charge are wear and tear, decay, obsolescence, and any additional requirements that may be imposed by regulators.

### 3. Miscellaneous Amortization Expenses

Miscellaneous amortization expenses represent costs incurred by a utility that are amortized over a specified period of time for rate purposes. Examples of such costs are cancelled plant amortizations and extraordinary property losses.

### 4. Taxes Other Than Income Taxes

Taxes other than income taxes include all payments a utility must make to various taxing authorities. Such taxes may be levied on utility sales and property; and for social security, unemployment compensation, franchise, and state and federal excise. Since the utility must pay these taxes in the process of doing business, such costs are eligible for recovery from customers. It should be noted that while revenue taxes (or gross receipts taxes) are considered as "other" taxes, such taxes are levied on all or a portion of the utility's revenues. Consequently, any incremental changes in a utility's revenue requirement determination will produce a corresponding change in these tax allowances.

### 5. Income Taxes

Income taxes, both federal and state, are levied on a utility's earnings. Consequently, such taxes represent a cost of doing business and are therefore recoverable from a utility's ratepayers. The development of income tax allowances included in rates is a complex process that requires familiarity with federal and state tax laws as well as accounting and ratemaking practices and principles that are adopted by the regulator.

### 6. Other Operating Revenues

Other operating revenues include all revenues received from sources other than retail sales of electricity. These amounts are collected by a utility for other services rendered. An example of these revenue sources is when a utility may provide space on its transmission or distribution poles for the use of cable television lines and receive revenues therefrom in the form of rental payments. In addition, revenues collected from non-firm opportunity sales or coordination type sales, are normally treated in the same manner as other operating revenues. The retail service customers are normally given credit for these revenues through a reduction in their revenue requirements since they are produced through the use of plant or utility personnel, the expenses of which are borne by the utility's retail service customers.

# SECTION II

## EMBEDDED COST STUDIES

SECTION II of the Cost Allocation Manual contains five chapters that detail the dominant method of cost allocation -- the embedded cost study; that is, cost allocation methods based on historical or known costs. Each chapter presents allocation methods for specific components of cost.

Chapter 4 describes embedded cost methods for allocating production costs. It first discusses functionalization and classification and differentiates between costs that are demand-related and energy-related. Next, a variety of methods that can be used to allocate production plant costs are presented with numerical examples. Finally, observations on choosing an embedded cost method are included along with data needs.

Chapter 5 discusses methods of transmission cost functionalization, with detailed attention paid to subfunctionalization methods. Next, several methods used to allocate transmission plant costs are presented. Finally, the treatment of wheeling costs is discussed.

Chapter 6 provides an overview of distribution plant cost allocation. It discusses the classification of distribution costs between energy, demand and customers. Two methods used to determine demand and customer components are outlined -- the minimum-size and minimum-intercept methods. Procedures used to calculate demand and allocation factors are finally presented.

Chapters 7 and 8 briefly outline the classification and allocation of customer-related costs and investment, administrative and general expenses, respectively.

# CHAPTER 4

## EMBEDDED COST METHODS FOR ALLOCATING PRODUCTION COSTS

Of all utility costs, the cost of production plant -- i.e., hydroelectric, oil and gas-fired, nuclear, geothermal, solar, wind, and other electric production plant -- is the major component of most electric utility bills. Cost analysts must devise methods to equitably allocate these costs among all customer classes such that the share of cost responsibility borne by each class approximates the costs imposed on the utility by that class.

The first three sections of this chapter discusses functionalization, classification and the classification of production function costs that are demand-related and energy-related. Section four contains a variety of methods that can be used to allocate production plant costs. The final three sections include observations regarding fuel expense data, operation and maintenance expenses for production and a summary and conclusion.

### I. THE FIRST STEP: FUNCTIONALIZATION

Functionalization is the process of assigning company revenue requirements to specified utility functions: Production, Transmission, Distribution, Customer and General. Distinguishing each of the functions in more detail -- subfunctionalization -- is an optional, but potentially valuable, step in cost of service analysis. For example, production revenue requirements may be subfunctionalized by generation type -- fossil, steam, nuclear, hydroelectric, combustion turbines, diesels, geothermal, cogeneration, and other. Distribution may be subfunctionalized to lines (underground and overhead) substations, transformers, etc. Such subfunctional categories may enable the analyst to classify and allocate costs more directly; they may be of particular value where the costs of specific units or types of units are assigned to time periods. But, since this is a manual of cost allocation, and this is a chapter on production costs, we won't linger over functionalization or consider costs in other functions. The interested reader will consult generalized texts on the subject. It will suffice to say here that all utility costs are allocated after they are functionalized.

## II. CLASSIFICATION IN GENERAL

Classification is a refinement of functionalized revenue requirements. Cost classification identifies the utility operation -- demand, energy, customer -- for which functionalized dollars are spent. Revenue requirements in the production and transmission functions are classified as demand-related or energy-related. Distribution revenue requirements are classified as either demand-, energy- or customer-related.

Cost classification is often integrated with functionalization; some analysts do not distinguish it as an independent step in the assignment of revenue requirements. Functionalization is to some extent reflected in the way the company keeps its books; plant accounts follow functional lines as do operation and maintenance (O&M) accounts. But to classify costs accurately the analyst more often refers to conventional rules and his own best judgment. Section IV of this chapter discusses three major methods for classifying and allocating production plant costs. We will see that the peak demand allocation methods rely on conventional classification while the energy weighting methods and the time-differentiated methods of allocation require much attention to classification and, indeed, are sophisticated classification methods with fairly simple allocation methods tacked on.

The chart below is a basic example of an integrated functionalization/classification scheme.

**FUNCTIONALIZED CLASSIFICATION OF ELECTRIC UTILITY COSTS**

| | Cost Classes | | | |
|---|---|---|---|---|
| **Functions** | **Demand** | **Energy** | **Customer** | **Revenue** |
| Production | | | | |
| Thermal | X | X | N/A | N/A |
| Hydro | X | X | N/A | N/A |
| Other | X | X | N/A | N/A |
| Transmission | X | X | X | N/A |
| Distribution | X | X | X | N/A |
| OH/UG Lines | X | X | X | N/A |
| Substations | X | X | X | N/A |
| Services | N/A | N/A | X | N/A |
| Meters | N/A | N/A | X | N/A |
| Customer | N/A | N/A | X | X |

## III. CLASSIFICATION OF PRODUCTION FUNCTION COSTS

Production plant costs can be classified in two ways between costs that are demand-related and those that are energy-related.

### A. Cost Accounting Approach

Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered or purchased and are classified as energy- related. Exhibit 4-1 summarizes typical classification of FERC Accounts 500-557.

**EXHIBIT 4-1**

**CLASSIFICATION OF PRODUCTION PLANT**

**CLASSIFICATION OF RATE BASE[1]**

**Production Plant**

| FERC Uniform System of Accounts No. | Description | Demand Related | Customer Related |
|---|---|---|---|
| 301-303 | Intangible Plant | x | - |
| 310-316 | Steam Production | x | x |
| 320-325 | Nuclear Production | x | - |
| 330-336 | Hydraulic Production | x | x[2] |
| 340-346 | Other Production | x | - |

**Exhibit 4-1**
**(Continued)**
**CLASSIFICATION OF PRODUCTION PLANT**

| FERC Uniform System of Accounts No. | Description | Demand Related | Energy Related |
|---|---|---|---|

**CLASSIFICATION OF EXPENSES[1]**
**Production Plant**

**Steam Power Generation Operations**

| | | | |
|---|---|---|---|
| 500 | Operating Supervision & Engineering | Prorated On Labor[3] | Prorated On Labor[3] |
| 501 | Fuel | - | x |
| 502 | Steam Expenses | x[4] | x[4] |
| 503-504 | Steam From Other Sources & Transfer. Cr. | - | x |
| 505 | Electric Expenses | x[4] | x[4] |
| 506 | Miscellaneous Steam Pwr Expenses | x | - |
| 507 | Rents | x | - |

**Maintenance**

| | | | |
|---|---|---|---|
| 510 | Supervision & Engineering | Prorated On Labor[3] | Prorated On Labor[3] |
| 511 | Structures | x | - |
| 512 | Boiler Plant | - | x |
| 513 | Electric Plant | - | x |
| 514 | Miscellaneous Steam Plant | - | x |

**Nuclear Power Generation Operation**

| | | | |
|---|---|---|---|
| 517 | Operation Supervision & Engineering | Prorated On Labor[3] | Prorated On Labor[3] |
| 518 | Fuel | - | x |
| 519 | Coolants and Water | x[4] | x[4] |
| 520 | Steam Expense | x[4] | x[4] |
| 521-522 | Steam From Other Sources & Transfe. Cr. | - | x |
| 523 | Electric Expenses | x[4] | x[4] |
| 524 | Miscellaneous Nuclear Power Expenses | x | - |
| 525 | Rents | x | - |

**EXHIBIT 4-1**

**(Continued)**

**CLASSIFICATION OF EXPENSES** [1]

| FERC Uniform System of Accounts No. | Description | Demand Related | Energy Related |
|---|---|---|---|

**Maintencance**

| | | | |
|---|---|---|---|
| 528 | Supervision & Engineering | Prorated on Labor[3] | Prorated on Labor[3] |
| 529 | Structures | x | - |
| 530 | Reactor Plant Equipment | - | x |
| 531 | Electric Plant | - | x |
| 532 | Miscellaneous Nuclear Plant | - | x |

**Hydraulic Power Generation Operation**

| | | | |
|---|---|---|---|
| 535 | Operation Supervision and Engineering | Prorated on Labor[3] | Prorated on Labor[3] |
| 536 | Water for Power | x | - |
| 537 | Hydraulic Expenses | x | - |
| 538 | Electric Expense | x[4] | x[4] |
| 539 | Misc Hydraulic Power Expenses | x | - |
| 540 | Rents | x | - |

**Maintenance**

| | | | |
|---|---|---|---|
| 541 | Supervision & Engineering | Prorated On Labor[3] | Prorated On Labor[3] |
| 542 | Structures | x | - |
| 543 | Reservoirs, Dams, and Waterways | x | x |
| 544 | Electric Plant | x | x |
| 545 | Miscellaneous Hydraulic Plant | x | x |

## Exhibit 4-1
## (Continued)

| FERC Uniform System of Account | Description | Demand Related | Energy Related |
|---|---|---|---|

### CLASSIFICATION OF EXPENSES[1]

#### Other Power Generation Operation

| | | | |
|---|---|---|---|
| 546, 548-554 | All Accounts | x | - |
| 547 | Fuel | - | x |

#### Other Power Supply Expenses

| | | | |
|---|---|---|---|
| 555 | Purchased Power | x[5] | x[5] |
| 556 | System Control & Load Dispatch | x | - |
| 557 | Other Expenses | x | - |

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

## B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH), reserve margin, or expected unserved energy (EUE); and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.

## IV. METHODS FOR CLASSIFYING AND ALLOCATING PRODUCTION PLANT COSTS

In the past, utility analysts thought that production plant costs were driven only by system maximum peak demands. The prevailing belief was that utilities built plants exclusively to serve their annual system peaks as though only that single hour was important for planning. Correspondingly, cost of service analysts used a single maximum peak approach to allocate production costs. Over time it became apparent to some that hours other than the peak hour were critical from the system planner's perspective, and utilities moved toward multiple peak allocation methods. The Federal Energy Regulatory Commission began encouraging the use of a method based on the 12 monthly peak demands, and many utilities accordingly adopted this approach for allocating costs within their retail jurisdictions as well as their resale markets.

This section is divided into three parts. The first two contain a discussion of peak demand and energy weighted cost allocation methods. The third part covers time-differentiated cost of service methods for allocating production plant costs. Tables 4-1 through 4-4 contain illustrative load data supplied by the Southern California Edison Company for monthly peak demands, summer and winter peak demands, class noncoincident peak demands, on-peak and off-peak energy use. These data are used to illustrate the derivation of various demand and energy allocation factors throughout this Section as well as Section III.

The common objective of the methods reviewed in the following two parts is to allocate production plant costs to customer classes consistent with the cost impact that the class loads impose on the utility system. If the utility plans its generating capacity additions to serve its demand in the peak hour of the year, then the demand of each class in the peak hour is regarded as an appropriate basis for allocating demand-related production costs.

If the utility bases its generation expansion planning on reliability criteria -- such as loss of load probability or expected unserved energy -- that have significant values in a number of hours, then the classes' demands in hours other than the single peak hour may also provide an appropriate basis for allocating demand-related production costs. Use of multiple-hour methods also greatly reduces the possibility of atypical conditions influencing the load data used in the cost allocation.

## TABLE 4-1

## CLASS MW DEMANDS AT THE GENERATION LEVL IN THE TWELVE MONTHLY SYSTEM PEAK HOURS

**(1988 Example Data)**

| Rate Class | January | February | March | April | May | June | July | August |
|---|---|---|---|---|---|---|---|---|
| DOM | 3,887 | 3,863 | 2,669 | 2,103 | 2,881 | 3,338 | 4,537 | 4,735 |
| LSMP | 3,065 | 3,020 | 3,743 | 4,340 | 4,390 | 4,725 | 5,106 | 5,062 |
| LP | 2,536 | 2,401 | 2,818 | 2,888 | 3,102 | 3,067 | 3,219 | 3,347 |
| AG&P | 84 | 117 | 144 | 232 | 405 | 453 | 450 | 447 |
| SL | 94 | 105 | 28 | 0 | 0 | 0 | 0 | 0 |
| Total | 9,666 | 9,506 | 9,402 | 9,563 | 11,318 | 11,583 | 13,312 | 13,591 |

| Rate Class | September | October | November | December | Total | Average |
|---|---|---|---|---|---|---|
| DOM | 4,202 | 2,534 | 3,434 | 4,086 | 42,268 | 3,522 |
| LSMP | 5,106 | 4,736 | 3,644 | 3,137 | 50,614 | 4,218 |
| LP | 3,404 | 3,170 | 2,786 | 2,444 | 35,181 | 2,932 |
| AG&P | 360 | 284 | 138 | 75 | 3,189 | 266 |
| SL | 0 | 0 | 103 | 126 | 457 | 38 |
| Total | 13,072 | 10,724 | 10,105 | 9,868 | 131,709 | 10,976 |

Note: The rate classes and their abbreviations for the example utility are as follows:

DOM - Domestic Service
LSMP - Lighting, Small and Medium Power
LP - Large Power
AG&P - Agricultural and Pumping
SL - Street Lighting

**TABLE 4-2**

**CLASS MW DEMANDS AT THE GENERATION LEVEL IN THE 3 SUMMER AND 3 WINTER SYSTEM PEAK HOURS**

**(1988 Example Data)**

| | Winter | | | | Summer | | | |
|---|---|---|---|---|---|---|---|---|
| Rate Class | January | February | December | Average | July | August | September | Average |
| DOM | 3,887 | 3,863 | 4,086 | 3,946 | 4,537 | 4,735 | 4,202 | 4,491 |
| LSMP | 3,065 | 3,020 | 3,137 | 3,074 | 5,106 | 5,062 | 5,106 | 5,092 |
| LP | 2,536 | 2,401 | 2,444 | 2,460 | 3,219 | 3,347 | 3,404 | 3,323 |
| A&P | 84 | 117 | 75 | 92 | 450 | 447 | 360 | 419 |
| SL | 94 | 105 | 126 | 108 | 0 | 0 | 0 | 0 |
| Total | 9,666 | 9,506 | 9,868 | 9,680 | 13,312 | 13,591 | 13,072 | 13,325 |

Peak demand methods include the single coincident peak method, the summer and winter peak method, the twelve monthly coincident peak method, multiple coincident peak method, and an all peak hours approach. Energy weighting methods include the average and excess method, equivalent peaker method, the base and peak method, and methods using judgmentally determined energy weightings, such as the peak and average method and variants thereof.

## A. Peak Demand Methods

Cost of service methods that utilize a peak demand approach are characterized by two features: First, all production plant costs are classified as demand-related. Second, these costs are allocated among the rate classes on factors that measure the class contribution to system peak. A customer or class of customers contributes to the system maximum peak to the extent that it is imposing demand at the time of -- coincident with -- the system peak. The customer's demand at the time of the system peak is that customer's "coincident" peak. The variations in the methods are generally around the number of system peak hours analyzed, which inturn depends on the utility's annual load shape and on system planning considerations.

Peak demand methods do not allocate production plant costs to classes whose usage occurs outside peak hours, to interruptible (curtailable) customers.

## TABLE 4-3
## DEMAND ALLOCATION FACTORS

| Rate Class | MW Demand At Annual System Peak (MW) | 1 CP Alloc. Factor (Percent) | Average of the 12 Monthly CP Demands (MW) | 12 CP Alloc. Factor (Percent) | Average of the 3 Summer CP Demands (MW) | Average of the 3 Winter CP Demands (MW) | 3S/3W Alloc. Factor (Percent) | Noncoinc. Peak Demand MW | NCP Alloc. Factor (Percent) |
|---|---|---|---|---|---|---|---|---|---|
| DOM | 4,735 | 34.84 | 3,522 | 32.09 | 4,491 | 3,946 | 36.67 | 5,357 | 36.94 |
| LSMP | 5,062 | 37.25 | 4,218 | 38.43 | 5,092 | 3,074 | 35.50 | 5,062 | 34.91 |
| LP | 3,347 | 24.63 | 2,932 | 26.71 | 3,323 | 2,460 | 25.14 | 3,385 | 23.34 |
| AG&P | 447 | 3.29 | 266 | 2.42 | 419 | 92 | 2.22 | 572 | 3.94 |
| SL | 0 | 0.00 | 38 | 0.35 | 0 | 108 | 0.47 | 126 | 0.87 |
| Total | 13,591 | 100.00 | 10,976 | 100.00 | 13,325 | 9,680 | 100.00 | 14,502 | 100.0 |

Note: Some columns may not add to indicated totals due to rounding.

## TABLE 4-4

## ENERGY ALLOCATION FACTORS

| Rate Class | Total Annual Energy Used (MWH) | Total Energy Allocation Factor (%) | On-Peak Energy Cons. (MWH) | On-Peak Energy Allocation Factor (%) | Off-Peak Energy Cons. (MWH) | Off-Peak Energy Allocation Factor (%) |
|---|---|---|---|---|---|---|
| DOM | 21,433,001 | 30.96 | 3,950,368 | 32.13 | 17,482,633 | 30.71 |
| LSMP | 23,439,008 | 33.86 | 4.452,310 | 36.21 | 18,986,698 | 33.35 |
| LP | 21,602,999 | 31.21 | 3,474,929 | 28.26 | 18,128,070 | 31.85 |
| AG&P | 2,229,000 | 3.22 | 335,865 | 2.73 | 1,893,135 | 3.33 |
| SL | 513,600 | 0.74 | 80,889 | 0.66 | 432,711 | 0.76 |
| Total | 69,217,608 | 100.00 | 12,294,361 | 100.00 | 56,923,247 | 100.00 |

Note: Some columns may not add to indicated totals due to rounding.

## 1. Single Coincident Peak Method (1-CP)

***Objective:*** The objective of the single coincident peak method is to allocate production plant costs to customer classes according to the load of the customer classes at the time of the utility's highest measured one-hour demand in the test year, the class coincident peak load.

***Data Requirements:*** The 1-CP method uses recorded and/or estimated monthly class peak demands. In a large system, this may require complex statistical sampling and data manipulation. A competent load research effort is a valuable asset.

***Implementation:*** Table 4-1 contains illustrative load data for five customer classes for 12 months of a test year. The analyst simply translates class load at the time of the system peak into a percentage of the company's total system peak, and applies that percentage to the company's production-demand revenue requirements; that is, to the revenue requirements that are functionalized to production and classified to demand. This operation is shown in Table 4-5.

**TABLE 4-5**

**CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE SINGLE COINCIDENT PEAK METHOD**

| Rate Class | MW Demand at Generator at System Peak | Allocation Factor | Total Class Production Plant Revenue Requirement |
|---|---|---|---|
| DOM | 4,735 | 34.84 | 369,461,692 |
| LSMP | 5,062 | 37.25 | 394,976,787 |
| LP | 3,347 | 24.63 | 261,159,089 |
| AG&P | 447 | 3.29 | 34,878,432 |
| SL | 0 | 0.00 | 0 |
| TOTAL | 13,591 | 100.00 | $ 1,060,476,000 |

## 2. Summer and Winter Peak Method

***Objective:*** The objective of the summer and winter peak method is to reflect the effect of two distinct seasonal peaks on customer cost assignment. If the summer and winter peaks are close in value, and if both significantly affect the utility's generation expansion planning, this approach may be appropriate.

***Implementation:*** The number of summer and winter peak hours may be determined judgmentally or by applying specified criteria. One method is simply to average the class contributions to the summer peak hour demand and the winter peak hour demand. Another method is to choose those summer and winter hours where the peak demand or reliability index passes a specified threshold value. Clearly, the selection of the hours is critical and the establishment of selection criteria is particularly important. These cost of service judgements must be made jointly with system planners and supported with good data. The analyst should review FERC cases, where this issue often comes up. Table 4-6 shows the allocators and resulting allocations of production plant revenue responsibility for the example using the three highest summer and three highest winter coincident peak demand hours.

**TABLE 4-6**

**CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE SUMMER AND WINTER PEAK METHOD**

| Rate Class | Average of the 3 Summer CP Demands (MW) | Average of the 3 Winter CP Demands (MW) | Demand Allocation Factor | Total Class Production Plant Revenue Requirmt |
|---|---|---|---|---|
| DOM | 4,491 | 3,946 | 36.67 | 388,925,712 |
| LSMP | 5,092 | 3,074 | 35.50 | 376,433,254 |
| LP | 3,323 | 2,460 | 25.14 | 266,582,600 |
| AG&P | 419 | 92 | 2.22 | 23,555,889 |
| SL | 0 | 108 | 0.47 | 4,978,544 |
| TOTAL | 13,325 | 9,680 | 100.00 | $ 1,060,476,000 |

## 3. The Sum of the Twelve Monthly Coincident Peak (12 CP) Method

*Objective:* This method uses an allocator based on the class contribution to the 12 monthly maximum system peaks. This method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky. The 12-CP method may be appropriate when the utility plans its maintenance so as to have equal reserve margins, LOLPs or other reliability index values in all months.

*Data Requirements:* Reliable monthly load research data for each class of customers and for the total system is the minimum data requirement. The data can be recorded and/or estimated.

*Implementation:* Table 4-7 shows the derivation of the 12 CP allocator and the resulting allocation of production plant costs for the example case.

**TABLE 4-7**

**CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE TWELVE COINCIDENT PEAK METHOD**

| Rate Class | Average of 12 Coincident Peaks At Generation (MW) | Allocation Factor | Total Class Production Plant Revenue Requirement |
|---|---|---|---|
| DOM | 3,522 | 32.09 | 340,287,579 |
| LSMP | 4,218 | 38.43 | 407,533,507 |
| LP | 2,932 | 26.71 | 283,283,130 |
| AG&P | 266 | 2.42 | 25,700,311 |
| SL | 38 | 0.35 | 3,671,473 |
| TOTAL | 10,976 | 100.00 | $ 1,060,476,000 |

## 4. Multiple Coincident Peak Method

This section discusses the general approach of using the classes' demands in a certain number of hours to derive the allocation factors for production plant costs. The number of hours may be determined judgmentally; e.g., the 10 or 20 hours in the year with the highest system demands, or by applying specified criteria. Criteria for determining which hours to use include: (1) all hours of the year with demands within 5 percent or 10 percent of the system's peak demand, and (2) all hours of the year in which a specified reliability index (loss of load probability, loss of load hours, expected unserved energy, or reserve margin) passes an established threshold value. This may result in a fairly large number of hours being included in the development of the demand allocator.

## 5. All Peak Hours Approach

This method resembles the multiple CP approach except it bases the allocation of demand-related production plant costs on the classes' contributions to all defined, rather than certain specified, on-peak hours. This method requires scrutiny of all hours of the year to determine which are most likely to contribute to the need for the utility to add production plant. If the on-peak rating periods -- i.e., the hours or periods in which on-peak rates apply -- are properly defined, then all hours in the on-peak period are critical from the utility's planning perspective. Table 4-8 shows the allocators and resulting cost allocation based on the classes' shares of on-peak KWH for the example utility. For the example utility, the on-peak periods are from 5:00 p.m. to 9:00 p.m. on winter weekdays and from 12:00 noon to 6:00 p.m. on summer weekdays.

The on-peak hours may be defined using various criteria, such as those hours with a preponderance of actual peak demands, those with the majority of annual loss of load probabilities, loss of load hours or those in which other reliability indexes register critical values. Using this method requires satisfactory load research and computer capability to estimate the classes' loads in the defined on-peak periods.

**TABLE 4-8**

**CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE ALL PEAK HOURS APPROACH**

| Rate Class | Class On-Peak MWH At Generation | Allocation Factor | Total Class Production Plant Revenue Requirement |
|---|---|---|---|
| DOM | 3,950,368 | 32.13 | 340,747,311 |
| LSMP | 4,452,310 | 36.21 | 384,043,376 |
| LP | 3,474,929 | 28.26 | 299,737,319 |
| AG&P | 335,865 | 2.73 | 28,970,743 |
| SL | 80,889 | 0.66 | 6,977,251 |
| TOTAL | 12,294,361 | 100.00 | $ 1,060,476,000 |

Notes: The on-peak periods for the example utility are from 5:00 p.m. to 9:00 p.m. on weekdays in January through May and October through December, and from 12:00 noon to 6:00 p.m. on weekdays in June through September. Some columns may not add to indicated totals due to rounding.

## 6. Summary: Peak Demand Responsibility Methods

Table 4-9 is a summary of the allocation factors and revenue allocations for the methods described above. The most important observations to be drawn from this information are:

- The number of hours chosen as the basis for the demand allocator can have a significant effect on the revenue allocation, even for relatively small numbers of hours.

- The greater the number of hours used, the more the allocation will reflect energy requirements. If all 8,760 hours of a year were used, the demand and a KWH (energy) allocation factors would be the same.

**TABLE 4-9**

**SUMMARY OF ALLOCATION FACTORS AND REVENUE RESPONSIBILITY FOR PEAK DEMAND COST ALLOCATION METHODS**

| | 1 CP Method | | 3 Summer and 3 Winter Peak Method | |
|---|---|---|---|---|
| **Rate Class** | **Allocation Factor (%)** | **Revenue Requirement** | **Allocation Factor (%)** | **Revenue Requirement** |
| DOM | 34.84 | 369,461,692 | 36.67 | 388,925,712 |
| LSMP | 37.25 | 394,976,787 | 35.50 | 376,433,254 |
| LP | 24.63 | 261,159,089 | 25.14 | 266,582,600 |
| AG&P | 3.29 | 34,878,432 | 2.22 | 23,555,889 |
| SL | 0.00 | 0 | 0.47 | 4,978,544 |
| TOTAL | 100.00 | $ 1,060,476,000 | 100.00 | $ 1,060,476,000 |

| | 12 CP Method | | All Peak Hours Approach | |
|---|---|---|---|---|
| **Rate Class** | **Allocation Factor (%)** | **Revenue Requirement** | **Allocation Factor (%)** | **Revenue Requirement** |
| DOM | 32.09 | 340,287,579 | 32.13 | 340,747,311 |
| LSMP | 38.43 | 407,533,507 | 36.21 | 384,043,376 |
| LP | 26.71 | 283,283,130 | 28.26 | 299,737,319 |
| AG&P | 2.42 | 25,700,311 | 2.73 | 28,970,743 |
| SL | 0.35 | 3,671,473 | 0.66 | 6,977,251 |
| TOTAL | 100.00 | $ 1,060,476,000 | 100.00 | $ 1,060,476,000 |

Note: Some columns may not add to totals due to rounding.

## B. Energy Weighting Methods

There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption. Table 4-4 shows allocators for the example utility for total energy, on-peak energy, and off-peak energy use.

In some cases, an energy allocator (annual KWH consumption or average demand) is used to allocate part of the production plant costs among the classes, but part or all of these costs remain classified as demand-related. Such methods can be characterized as partial energy weighting methods in that they take the first step of allocating some portion of production plant costs to the classes on the basis of their energy loads but do not take the second step of classifying the costs as energy- related.

### 1. Average and Excess Method

***Objective:*** The cost of service analyst may believe that average demand rather than coincident peak demand is a better allocator of production plant costs. The average and excess method is an appropriate method for the analyst to use. The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands.

***Data Requirements:*** The required data are: the annual maximum and average demands for each customer class and the system load factor. All production plant costs are usually classified as demand-related. The allocation factor consists of two parts. The first component of each class's allocation factor is its proportion of total average demand (or energy consumption) times the system load factor. This effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. The second component of each class's allocation factor is called the "excess demand factor." It is the proportion of the difference between the sum of all classes' non-coincident peaks and the system average demand. The difference may be negative for curtailable rate classes. This component is multiplied by the remaining proportion of production plant -- i.e., by 1 minus the system load factor -- and then added to the first component to obtain the "total allocator." Table 4-10A shows the derivation of the allocation factors and the resulting allocation of production plant costs using the average and excess method.

## TABLE 4-10A

### CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

| Class Rate | Demand Allocation Factor - NCP MW | Average Demand (MW) | Excess Demand (NCP MW - Avg. MW) | Average Demand Component of Alloc. Factor | Excess Demand Component of Alloc. Factor | Total Allocation Factor (%) | Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|---|---|
| DOM | 5,357 | 2,440 | 2,917 | 17.95 | 18.51 | 36.46 | 386,683,685 |
| LSMP | 5,062 | 2,669 | 2,393 | 19.64 | 15.18 | 34.82 | 369,289,317 |
| LP | 3,385 | 2,459 | 926 | 18.09 | 5.88 | 23.97 | 254,184,071 |
| AG&P | 572 | 254 | 318 | 1.87 | 2.02 | 3.89 | 41,218,363 |
| SL | 126 | 58 | 68 | 0.43 | 0.43 | 0.86 | 9,101,564 |
| TOTAL | 14,502 | 7,880 | 6,622 | 57.98 | 42.02 | 100.00 | $1,060,476,000 |

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows production plant classified as demand-related.

Some columns may not add to indicated totals due to rounding.

If your objective is -- as it should be using this method --to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands.

The example on Table 4-10B illustrates this problem. In the example, the excess demand component of the allocation factor for the Street Lighting and Outdoor Lighting (SL/OL) class is <u>negative</u> and <u>reduces</u> the class's allocation factor to what it would be if a single CP method were used in the first place. (See third column of Table 4-3.)

**TABLE 4-10B**

**CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD (SINGLE CP DEMAND FACTOR)**

| Rate Class | Demand Allocation Factor - Single CP NCP MW | Average Demand (MW) | Excess Demand (Single CP MW - Avg. MW) | Average Demand Component of Allocation Factor | Excess Demand Component of Allocation Factor | Total Allocation Factor (%) | Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|---|---|
| DOM | 4,735 | 2,440 | 2,295 | 17.95 | 16.89 | 34.84 | 369,461,692 |
| LSMP | 5,062 | 2,669 | 2,393 | 19.64 | 17.61 | 37.25 | 394,976,787 |
| LP | 3,347 | 2,459 | 888 | 18.09 | 6.53 | 24.63 | 261,159,089 |
| AG&P | 447 | 254 | 193 | 1.87 | 1.42 | 3.29 | 34,878,432 |
| SL | 0 | 58 | -58 | 0.43 | -0.43 | 0.00 | 0 |
| TOTAL | 13,591 | 7,880 | 5,711 | 57.98 | 42.02 | 100.00 | $1,060,476,000 |

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows all production plant classified as demand-related. Note that the total allocation factors are exactly equal to those derived using the single coincident peak method shown in the third column of Table 4-3.

Some columns may not add to indicated totals due to rounding.

Some analysts argue that the percentage of total production plant that is equal to the system load factor percentage should be classified as energy-related and not demand-related. This could be important because, although classifying the system load factor percentage as energy-related might not affect the allocation <u>among</u> classes, it could significantly affect the apportionment of costs <u>within</u> rate classes. Such a classification could also affect the allocation of production plant costs to interruptible service, if the utility or the regulatory authority allocated energy-related production plant costs but not demand-related production plant costs to the interruptible class. Table 4-10C presents the allocation factors and production plant revenue requirement allocations for an average and excess cost of service study with the system load factor percentage classified as energy-related.

TABLE 4-10C

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

(AVERAGE DEMAND PROPORTION ALLOCATED ON ENERGY)

| Rate Class | Energy Allocation Factor - Average MW | Energy Allocatn. Factor (%) | Energy-Related Production Plant Revenue Requirement | Excess Demand Allocation Factor (NCP MW - Avg. MW) | Excess Demand Alloctn. Factor (Percent) | Demand-Related Production Plant Revenue Requirement | Class Production Plant Revenue Requiremnt |
|---|---|---|---|---|---|---|---|
| DOM | 2,440 | 30.96 | 190,387,863 | 2,917 | 44.05 | 196,294,822 | 386,682,685 |
| LSMP | 2,669 | 33.87 | 208,256,232 | 2,393 | 36.14 | 161,033,085 | 369,289,317 |
| LP | 2,459 | 31.21 | 191,870,391 | 926 | 13.98 | 62,313,680 | 254,184,071 |
| AG&P | 254 | 3.22 | 19,819,064 | 318 | 4.80 | 21,399,298 | 41,218,363 |
| SL | 58 | 0.74 | 4,525,613 | 68 | 1.03 | 4,575,951 | 9,101,564 |
| TOTAL | 7,880 | 100.00 | 614,859,163 | 6,622 | 100.00 | 445,616,837 | 1,060,476,000 |

Notes: The system load factor is 57.98 percent (7,880 MW/13,591 MW). Thus, 57.98 percent of total production plant revenue requirement is classified as energy-related and allocated to all classes on the basis of their proportions of average system demand. The remaining 42.02 percent is classified as demand-related and allocated to the classes according to their proportions of excess (NCP - average) demand, and allocated to the firm service classes according to their proportions of excess (NCP - average) demand.

Some columns may not add to indicated totals due to rounding.

## 2. Equivalent Peaker Methods

***Objective:*** Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. They generally result in significant percentages (40 to 75 percent) of total production plant costs being classified as energy-related, with the results that energy unit costs are relatively high and the revenue responsibility of high load factor classes and customers is significantly greater than indicated by pure peak demand responsibility methods.

The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.

***Data Requirements:*** This energy weighting method takes a different tack toward production plant cost allocation, relying more heavily on system planning data in addition to load research data. The cost of service analyst must become familiar with system expansion criteria and justify his cost classification on system planning grounds.

## *A Digression on System Planning with Reference to Plant Cost Allocation:*

Generally speaking, electric utilities conduct generation system planning by evaluating the need for additional capacity, then, having determined a need, choosing among the generation options available to it. These include purchases from a neighboring utility, the construction of its own peaking, intermediate or baseload capacity, load management, enhanced plant availability, and repowering among others.

The utility can choose to construct one of a variety of plant-types: combustion turbines (CT), which are the least costly per KW of installed capacity, combined cycle (CC) units costing two to three times as much per KW as the CT, and baseloaded units with a cost of four or more times as much as the CT per KW of installed capacity. The choice of unit depends on the energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit.

## *Classification of Generation:*

In the equivalent peaker type of cost study, all costs of actual peakers are classified as demand-related, and other generating units must be analyzed carefully to determine their proportionate classifications between demand and energy. If the plant types are significantly different, then individual analysis and treatment may be necessary. The ideal analysis is a "date of service" analysis. The analyst calculates the installed cost of all units in the dollars of the install date and classifies the peaker cost as demand-related. The remaining costs are classified as energy-related.

A variant of the above approach is to do the equivalent peaker cost evaluations based only on the viable generation alternatives available to the utility at any point in time. For example, combined cycle technology might be so much more cost-effective than the next best option that it would be the preferred choice for demand lasting as little as 50 to 100 hours. If so, then using a combustion turbine as the equivalent peaker "benchmark" might be inappropriate. Such choices would require careful analysis of alternate generation expansion paths on a case by case basis.

Consider the example shown in Table 4-11. The example utility has three 100 MW combustion turbines of varying ages. All investment in these units is classified as demand-related. The utility also has three unscrubbed coal-fired units of varying ages. The production plant costs of these units are classified as follows: first, the ratio of the cost of a new CT ($300/KW) to the cost of a new unscrubbed coal unit ($1000/KW) is calculated and found to be 30 percent. Then, this factor is multiplied by the rate base for each plant, and the result is classified as demand-related, with the remainder classified as energy-related. The cost of the utility's new, scrubbed coal unit is classified by the same method. Since the unit cost is $1200/KW, only 25 percent of it ($300/KW)/($1200/KW) is classified as demand-related, with the remaining three-fourths classified as energy-related. Treating the utility's nuclear unit similarly, only 15 percent of its cost ($300/KW)/($2000/KW) is classified as demand-related.

**TABLE 4-11**

**ILLUSTRATION OF DEMAND AND ENERGY AND ENERGY CLASSIFICATION OF GENERATING UNITS USING THE EQUIVALENT PEAKER METHOD**

| Unit | Unit Type | Capacity (MW) | Rate Base | Percent Class Demand-Related | Demand-Related Rate Base | Energy-Related Rate Base |
|---|---|---|---|---|---|---|
| A | CT | 100 | 10,000,000 | 100 | 10,000,000 | 0 |
| B | CT | 100 | 20,000,000 | 100 | 20,000,000 | 0 |
| C | CT | 100 | 30,000,000 | 100 | 30,000,000 | 0 |
| D | Coal | 200 | 80,000,000 | 30 | 24,000,000 | 56,000,000 |
| E | Coal | 250 | 100,000,000 | 30 | 30,000,000 | 70,000,000 |
| F | Coal | 450 | 270,000,000 | 30 | 81,000,000 | 189,000,000 |
| G | Coal W/FDG | 600 | 720,000,000 | 25 | 180,000,000 | 540,000,000 |
| H | Nuclear | 900 | 1,800,000,000 | 15 | 270,000,000 | 1,530,000,000 |
| TOTAL | | 2,700 | $ 3,030,000,000 | 21 | $ 645,000,000 | $ 2,385,000,000 |

The equivalent peaker classification method applied in the example above ignores the fuel savings that accrue from running a base unit rather than a peaker. Discussions with planners can help incorporate the effects of fuel savings into the classification.

Table 4-12 shows the revenue responsibility for the rate classes using the equivalent peaker cost method applied to the example utility's data. In this example, a summer and winter peak demand allocator was used to allocate the demand-related costs. Observe that the total revenue requirement allocation among the rate classes is significantly different from that resulting from any of the pure peak demand responsibility methods.

**TABLE 4-12**

**CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE EQUIVALENT PEAKER COST METHOD**

| Rate Class | Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%) | Demand-Related Production Plant Revenue Requirement | Energy Allocation Factor (Total MWH) | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requiremnt |
|---|---|---|---|---|---|
| DOM | 36.67 | 78,980,827 | 30.96 | 261,678,643 | 340,659,471 |
| LSMP | 35.50 | 76,460,850 | 33.87 | 286,237,828 | 362,698,678 |
| LP | 25.14 | 54,147,205 | 31.21 | 263,716,305 | 317,863,510 |
| AG&P | 2.22 | 4,781,495 | 3.22 | 27,240,318 | 32,021,813 |
| SL | 0.47 | 1,012,299 | 0.74 | 6,220,230 | 7,232,529 |
| TOTAL | 100.00 | 215,382,676 | 100.00 | 845,093,324 | $1,060,476,000 |

Note: Some columns may not add to indicated totals due to rounding.

## 3. Base and Peak Method

***Objective:*** The objective of the base and peak method is to reflect in cost allocation the argument that an on-peak kilowatt-hour costs more than an off-peak kilowatt-hour and that the extra cost should be borne by the customers imposing it. This approach first identifies the same production plant cost components as the equivalent peaker cost method, and allocates demand-related production plant costs in the same way. The difference is that, using the base and peak method, the energy-related excess capital costs are allocated on the basis of the classes' proportions of on-peak energy use instead of being allocated according to the classes' shares of total system energy use. The logic of this approach is that the extra capital costs would be incurred once the system was expected to run for a certain minimum number of hours; i.e., once the break-even point in unit run time between a peaker and a baseload (or intermediate) unit was reached. However, system planners generally recognize no difference between on-peak hours and off-peak energy loads on the decision to build a baseload power plant, instead, the belief is that system planners consider the total annual energy loads that determine the type of plant to build. To allocate energy-related production plant costs on the basis of only on-peak energy use implies a differential impact of on-peak KWH as compared to off-peak KWH that may or may not exist.

Table 4-13 shows the results of a base and peak cost of service method for the example utility.

**TABLE 4-13**

**CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE BASE AND PEAK METHOD**

| Rate Class | Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%) | Demand-Related Production Plant Revenue Requirement | Energy Allocation Factor On-Peak MWH | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|
| DOM | 36.67 | 78,980,827 | 32.13 | 271,541,532 | 350,522,360 |
| LSMP | 35.50 | 76,460,850 | 36.21 | 306,044,166 | 382,505,016 |
| LP | 25.14 | 54,147,205 | 28.26 | 238,860,669 | 293,007,874 |
| AG&P | 2.22 | 4,781,495 | 2.73 | 23,086,785 | 27,868,280 |
| SL | 0.47 | 1,012,299 | 0.66 | 5,560,171 | 6,572,470 |
| TOTAL | 100.00 | 215,382,676 | 100.00 | 845,093,324 | $1,060,476,000 |

Note: Some columns may not add to indicated totals due to rounding.

## 4. Judgmental Energy Weightings

Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally-established energy weighting into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specified group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand. Two variants of this allocation method are shown in Tables 4-14 and 4-15.

**TABLE 4-14**

**CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 1 CP AND AVERAGE DEMAND METHOD**

| Rate Class | Demand Allocation Factor - 1 CP MW (Percent) | Demand-Related Production Plant Revenue Requirement | Avg. Demand (Total MWH) Allocation Factor | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|
| DOM | 34.84 | 233,869,251 | 30.96 | 120,512,062 | 354,381,313 |
| LSMP | 37.25 | 250,020,306 | 33.87 | 131,822,415 | 381,842,722 |
| LP | 24.63 | 165,313,703 | 31.21 | 121,450,476 | 286,764,179 |
| AG&P | 3.29 | 22,078,048 | 3.22 | 12,545,108 | 34,623,156 |
| SL | 0.00 | 0 | 0.74 | 2,864,631 | 2,864,631 |
| TOTAL | 100.00 | 671,281,308 | 100.00 | 389,194,692 | $1,060,476,000 |

Notes: The portion of the production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of (a) the annual system peak demand, Table 4-3, column 2, plus (b) the average system demand for the test year, Table 4-10A, column 3. Thus, the percentage classified as demand-related is equal to 13591/(13591+7880), or 63.30 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the system peak demand and the average system demand. For the example, this percentage is 36.70 percent.

Some columns may not add to indicated totals due to rounding.

## TABLE 4-15

## CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND AVERAGE DEMAND METHOD

| Rate Class | Demand Allocation Factor - 12 CP MW (Percent) | Demand-Related Production Plant Revenue | Average Demand (Total MWH) Allocation Factor | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|
| DOM | 32.09 | 198,081,400 | 30.96 | 137,226,133 | 335,307,533 |
| LSMP | 38.43 | 237,225,254 | 33.87 | 150,105,143 | 387,330,397 |
| LP | 26.71 | 164,899,110 | 31.21 | 138,294,697 | 303,193,807 |
| AG&P | 2.42 | 14,960,151 | 3.22 | 14,285,015 | 29,245,167 |
| SL | 0.35 | 2,137,164 | 0.74 | 3,261,933 | 5,399,097 |
| TOTAL | 100.00 | 617,303,080 | 100.00 | 443,172,920 | $1,060,476,000 |

Notes: The portion of production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of the 12 monthly system coincident peaks (Table 4-3, column 4) by the sum of that value plus the system average demand (Table 4-10A, column 3). Thus, for example, the percentage classified as demand-related is equal to 10976/(10976+7880), or 58.21 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the average demand and the average of the twelve monthly peak demands. For the example, 41.79 percent of production plant revenue requirements are classified as energy-related.

Another variant of the peak and average demand method bases the production plant cost allocators on the 12 monthly CPs and average demand, with 1/13th of production plant classified as energy-related and allocated on the basis of the classes' KWH use or average demand, and the remaining 12/13ths classified as demand-related. The resulting allocation factors and allocations of revenue responsibility are shown in Table 4-16 for the example data.

TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

| Rate | Demand Allocation Factor - 12 CP MW (Percent) | Demand-Related Production Plant Revenue Requirement | Average Demand (Total MWH) Allocation Factor | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|
| DOM | 32.09 | 314,111,612 | 30.96 | 25,259,288 | 339,370,900 |
| LSMP | 38.43 | 376,184,775 | 33.87 | 27,629,934 | 403,814,709 |
| LP | 26.71 | 261,492,120 | 31.21 | 25,455,979 | 286,948,099 |
| AG&P | 2.42 | 23,723,364 | 3.22 | 2,629,450 | 26,352,815 |
| SL | 0.35 | 3,389,052 | 0.74 | 600,426 | 3,989,478 |
| TOTAL | 100.00 | 978,900,923 | 100.00 | 81,575,077 | $1,060,476,000 |

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

Some columns may not add to indicated totals due to rounding.

## C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

### 1. Production Stacking Methods

***Objective:*** The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. Various base load level options are available: average annual load, minimum annual load, average off-peak load, and maximum off-peak load.

*Implementation:* In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. These are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

An example of a production stack cost of service study is presented in Table 4-17. This particular method simply identified the utility's nuclear, coal-fired and hydroelectric generating units as the production stack to be classified as energy-related. The rationale for this approach is that these are truly baseload units. Additionally, the combined capacity of these units (4,920.7 MW) is significantly less than either the utility's average demand (7,880 MW) or its average off-peak demand (7,525.5 MW); thus, to get up to the utility's average off-peak demand would have required adding oil and gas-fired units, which generally are not regarded as baseload units. This method results in 89.72 percent of production plant being classified as energy-related and 10.28 percent as demand-related. The allocation factor and the classes' revenue responsibility are shown in Table 4-17.

## 2. Base-Intermediate-Peak (BIP) Method

The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components. In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only.

## TABLE 4-17

## CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING A PRODUCTION STACKING METHOD

| Rate Class | Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%) | Demand-Related Production Plant Revenue Requirement | Energy Allocation Factor (Total MWH) | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|
| DOM | 36.67 | 39,976,509 | 30.96 | 294,614,229 | 334,590,738 |
| LSMP | 35.50 | 38,701,011 | 33.87 | 322,264,499 | 360,965,510 |
| LP | 25.14 | 27,406,857 | 31.21 | 296,908,356 | 324,315,213 |
| AG&P | 2.22 | 2,420,176 | 3.22 | 30,668,858 | 33,089,034 |
| SL | 0.47 | 512,380 | 0.74 | 7,003,125 | 7,515,505 |
| TOTAL | 100.00 | 109,016,933 | 100.00 | 951,459,067 | $1,060,476,000 |

Note: This allocation method uses the same allocation factors as the equivalent peaker cost method illustrated in Table 4-12. The difference between the two studies is in the proportions of production plant classified as demand- and energy-related. In the method illustrated here, the utility's identified baseload generating units -- its nuclear, coal-fired and hydroelectric generating units -- were classified as energy-related, and the remaining units -- the utility's oil- and gas-fired steam units, its combined cycle units and its combustion turbines -- were classified as demand-related. The result was that 89.72 percent of the utility's production plant revenue requirement was classified as energy-related and allocated on the basis of the classes' energy consumption, and 10.28 percent was classified as demand-related and allocated on the basis of the classes' contributions to the 3 summer and 3 winter peaks.

Some columns may not add to indicated totals due to rounding

There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period.

In a BIP study, production plant costs may be classified as energy-related or demand-related. If the analyst believes that the classes' energy loads or off-peak average demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

### 3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

### 4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

## TABLE 4-18

### SUMMARY OF PRODUCTION PLANT COST ALLOCATIONS USING DIFFERENT COST OF SERVICE METHODS

| | 1 CP METHOD | | 12 CP METHOD | | 3 SUMMER & 3 WINTER PEAK METHOD | | ALL PEAK HOURS APPROACH | | AVERAGE AND EXCESS METHOD | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total |
| DOM | $ 369,461,692 | 34.84 | $ 340,287,579 | 32.09 | $ 388,925,712 | 36.67 | $ 340,747,311 | 32.13 | $ 386,682,685 | 36,46 |
| LSMP | 394,976,787 | 37.25 | 407,533,507 | 38.43 | 376,433,254 | 35.50 | 384,043,376 | 36.21 | 369,289,317 | 34.82 |
| LP | 261,159,089 | 24.63 | 283,283,130 | 26.71 | 266,582,600 | 25.14 | 299,737,319 | 28.26 | 254,184,071 | 23.97 |
| AG&P | 34,878,432 | 3.29 | 25,700,311 | 2.42 | 23,555,089 | 2.22 | 28,970,743 | 2.73 | 41,218,363 | 3.89 |
| SL | 0 | 0.00 | 3,671,473 | 0.35 | 4,978,544 | 0.47 | 6,977,251 | 0.66 | 9,101,564 | 0.86 |
| Total | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.0 | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.0 | $1,060,476,000 | 100.0 |

| | EQUIVALENT PEAKER COST METHOD | | BASE AND PEAK METHOD | | 1 CP AND AVERAGE DEMAND METHOD | | 12 CP AND 1/13th AVERAGE DEMAND METHOD | | PRODUCTION STACKING METHOD | |
|---|---|---|---|---|---|---|---|---|---|---|
| Rate Class | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total |
| DOM | $ 340,657,471 | 32.12 | $ 3350,522,360 | 33.05 | $ 354,381,313 | 33.42 | $ 339,370,900 | 32.00 | $ 334,590,738 | 31.55 |
| LSMP | 362,698,678 | 34.20 | 382,505,016 | 36.07 | 381,842,722 | 36.01 | 403,814,709 | 38.08 | 360,965,510 | 34.04 |
| LP | 317,863,510 | 29.97 | 293,007,874 | 27.63 | 286,764,179 | 27.04 | 286,948,099 | 27.06 | 324,315,213 | 30.58 |
| AG&P | 32,021,813 | 3.02 | 27,868,280 | 2.63 | 34,623,156 | 3.36 | 26,352,815 | 2.48 | 33,089,034 | 3.12 |
| SL | 7,232,529 | 0.68 | 6,572,470 | 0.62 | 2,864,631 | 0.27 | 3,989,478 | 0.38 | 7,515,505 | 0.71 |
| Total | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.00 |

### 5. Summary

Table 4-18 summarizes the percentage allocation factors and revenue allocations for the cost of service methodologies presented in this chapter. Important observations are: (1) that the proportions of production plant costs classified as demand-related and energy-related can have dramatic effects on the revenue allocation; and (2) the greater the proportion classified as energy-related, the greater is the revenue responsibility of high load factor classes and the less is the revenue responsibility of low-load factor classes.

## V. FUEL EXPENSE DATA

Fuel expense data can be obtained from the FERC Form 1. Aggregate fuel expense data by generation type is found in Accounts 501, 518, and 547. Annual fuel expense by fuel type for specified generating stations can be found on pages 402 and 411 of Form 1.

Fuel expense is almost always classified as energy-related. It is allocated using appropriate time-differentiated allocators; e.g., on-peak KWH and off-peak KWH, or non-time-differentiated energy allocators (total KWH) calculated by incorporating adjustments to reflect different line and transformation losses at different levels of the utility's transmission and distribution system. Depending on the cost of service method used, it may be necessary to directly assign fuel expense to classes that are directly assigned the cost responsibility for specific generating units. Table 4-19 shows the allocation of fuel expense, other operation and maintenance expenses and purchased power expenses for the example utility. Fuel and purchased power expenses were allocated according to the classes' energy use at the generator level. Other operation and maintenance expenses were allocated using demand and energy allocators and ratio methods.

## VI. OTHER OPERATIONS AND MAINTENANCE EXPENSES FOR PRODUCTION

Other production O&M costs may also be classified as demand-related or energy-related. Typically, any costs that vary directly with the amount of energy produced, such as purchased steam, variable water cost and water treatment chemical costs, are classified as energy-related and allocated using appropriate energy allocation factors. Such cost items would typically be booked in Accounts 502 through 505 for fossil power steam generation, Accounts 519 and 520 for nuclear power generation, and Accounts 548 and 550.1 for other generation (excluding hydroelectric).

TABLE 4-19
ALLOCATED GENERATION FUEL, OPERATION, AND MAINTENANCE EXPENSES
(Thousands of Dollars)

| EXPENSE CATEGORY | TOTAL COMPANY RETAIL | DOMESTIC | LIGHTING, SMALL AND MEDIUM POWER | LARGE POWER | AGRICULTURAL AND PUMPING | STREET LIGHTING |
|---|---|---|---|---|---|---|
| Total Fuel | $ 871,598 | $269,887 | $295,147 | $272,028 | $28,068 | $ 6,467 |
| Steam Generation Expenses | | | | | | |
| Operation Expenses | 53,740 | 17,246 | 20,652 | 14,355 | 1,301 | 186 |
| Maintenance Expenses | 176,117 | 54,632 | 60,037 | 54,574 | 5,601 | 1,272 |
| Total Steam Excl. Fuel | 229,857 | 71,879 | 80,688 | 68,929 | 6,902 | 1,459 |
| Nuclear Generation Expenses | | | | | | |
| Operation Expenses | 106,851 | 34,291 | 41,061 | 28,541 | 2,587 | 371 |
| Maintenance Expenses | 88,787 | 27,552 | 30,305 | 27,475 | 2,817 | 638 |
| Total Nuclear Excl. Fuel | 195,638 | 61,842 | 71,366 | 56,017 | 5,404 | 1,009 |
| Hydraulic Generation Expenses | | | | | | |
| Operation Expenses | 9,730 | 3,054 | 3,462 | 2,872 | 284 | 58 |
| Maintenance Expenses | 13,135 | 4,123 | 4,674 | 3,877 | 383 | 78 |
| Total Hydraulic Expenses | 22,865 | 7,177 | 8,136 | 6,749 | 667 | 136 |
| Other Generation Expenses | | | | | | |
| Operation Expenses | 20,461 | 6,563 | 7,953 | 5,358 | 516 | 70 |
| Maintenance Expenses | 10,371 | 3,327 | 4,020 | 2,729 | 259 | 36 |
| Total Other Excl. Fuel | 30,832 | 9,890 | 11,973 | 8,087 | 775 | 106 |
| Purchased Power | 1,275,663 | 395,005 | 431,975 | 398,138 | 41,080 | 9,466 |
| System Control & Dispatch | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | $2,626,453 | $815,680 | $899,285 | $809,948 | $82,896 | $18,643 |

Note: Some values may not add to indicated totals or sub-totals due to rounding.

Operations and maintenance costs that do not vary directly with energy output may be classified and allocated by different methods. If certain costs are specifically related to serving particular rate classes, they are directly assigned. Some accounts may be easily identified as being all demand-related or all energy-related; these may then be allocated using appropriate demand andenergy allocators. Other accounts contain both demand-related and energy-related components. One common method for handling such accounts is to separate the labor expenses from the materials expenses: labor costs are then considered fixed and therefore demand-related, and materials costs are considered variable and thus energy-related. Another common method is to classify each account according to its "predominant" -- i.e., demand-related or energy-related -- character. Certain supervision and engineering expenses can be classified on the basis of the prior classification of O&M accounts to which these overhead accounts are related. Although not standard practice, O&M expenses may also be classified and allocated as the generating plants at which they are incurred are allocated.

## VII. SUMMARY AND CONCLUSION

### A. Choosing a Production Cost Allocation Method

As we have seen in the catalog of cost allocation methods above, the analyst chooses a method after considering many complex factors: (1) the utility's generation system planning and operation; (2) the cost of serving load with new generation or purchased power; (3) the incidence of new load on an annual, monthly and hourly basis; (4) the availability of load and operations data; and (5) the rate design objectives.

### B. Data Needs and Sources

Most of the cost of service methods reviewed above require: (1) rate base data; (2) operations and maintenance expense data, depreciation expense data, and tax data; and (3) peak demand and energy consumption data for all rate classes. Some methods also require information from the utility's system planners regarding the operation of specific generating units and more general data such as generation mix, types of plants and the plant loading; for example, how often the units are operated, and whether they are run as baseload, intermediate or peaking units. Rate base, O&M, depreciation, tax and revenue data are generally available from the FERC Form 1 reports that follow the uniform system of accounts prescribed by FERC for utilities (18 CFR Chapter 1, Subchapter C, Part 101). See Chapter 3 for a complete discussion of revenue requirements. Load data may be gathered by the utility or borrowed from similar neighboring utilities if necessary. Data or information relating to specific generating units must be obtained from the utility's system planners and power-system operators.

## C. Class Load Data

Any cost of service method that allocates part or all of production plant costs using a peak demand allocator requires at least estimates of the classes' peak demands. These may be estimates of the classes' coincident peak (CP) or non-coincident class peak (NCP) demands.

For larger utilities, class load data is generally developed from statistical samples of customers with time-recording demand and energy meters. Utilities without a load research program can sometimes borrow load data from others. See Appendix A for a thorough discussion of development of data through load research studies.

Different cost of service methods have different data requirements. The requirements may be as simple as: (1) total energy usage, adjusted for different line and transformation losses to be comparable at the generation level; (2) the class coincident peak demands in the peak hour of the year; and (3) the class non-coincident peak demands for the year. Some methods require much more complex data, ranging from class CP demands in each of the 12 monthly peak hours to estimated class demands in each hour of the year. Thus, load data development and analysis for cost of service studies entail substantial effort and cost.

## D. System and Unit Dispatch Data

Some methods, such as the base-intermediate-peak methods, require classification of units according to their primary operating function. This may involve judgmental classification by system planners or power system operators. Other methods, such as the probability of dispatch methods, require either actual or modeled data regarding specific units' operation on an hour-by-hour basis, as well as hourly load data. Production stacking methods require data on the dispatch configuration of units, including reserves, required to serve a given load level. Such data must be developed and maintained by the utility.

## E. Conclusion

This review of production cost allocation methods may not contain every method, but it is hoped that the reader will agree that the broad outlines of all methods are here. The possibilities for varying the methods are numerous and should suit the analysts' assessment of allocation objectives. Keep in mind that no method is prescribed by regulators to be followed exactly; an agreed upon method can be revised to reflect new technology, new rate design objectives, new information or a new analyst with new ideas. These methods are laid out here to reveal their flexibility; they can be seen as maps and the road you take is the one that best suits you.

# SECTION III

## MARGINAL COST STUDIES

SECTION III reviews marginal cost of service studies. As noted in Chapter 2, in contrast to embedded studies where the issues primarily involve the allocation of costs taken from the company's books, the practical and theoretical debates in marginal cost studies center around the development of the costs themselves.

Chapter 9 discusses marginal production costs, including the costing methodologies and allocation to time periods and customer classes of the energy and capacity components.

Chapter 10 discusses the costing methodologies and allocation issues for marginal transmission, distribution and customer charges.

Use of marginal cost methodologies in ratemaking is based on arguments of economic efficiency. Pricing a utility's output at marginal cost, however, will only by rare coincidence recover the allowed revenue requirement.

Chapter 11 discusses the major approaches used to reconcile the marginal cost results to the revenue requirement.

# CHAPTER 9

## MARGINAL PRODUCTION COST

Marginal production cost is the change in the cost of producing electricity in response to a small change in customer usage. Marginal production cost includes an energy production component, referred to as marginal energy cost, and a generation-related reliability component, referred to as marginal capacity cost. Marginal capacity cost is one reliability-related component of the marginal costs associated with a change in customer usage. The other components, marginal transmission cost and marginal distribution cost, are discussed in Chapter 10. Together, these three reliability-related marginal costs are sometimes referred to as marginal demand cost. These marginal costs are used to calculate marginal cost revenues, which are used in cost allocation, as discussed in Chapter 11.

Marginal costs are commonly time-differentiated to reflect variations in the cost of serving additional customer usage during the course of a day or across seasons. Marginal production costs tend to be highest during peak load periods when generating units with the highest operating costs are on line and when the potential for generation-related load curtailments or interruptions is greatest. A costing period is a unit of time in which costs are separately identified and causally attributed to different classes of customers. Costing periods are often disaggregated hourly in marginal cost studies, particularly for determining marginal capacity costs which are usually strongly related to hourly system load levels. A rating period is a unit of time over which costs are averaged for the purpose of setting rates or prices. Rating periods are selected to group together periods with similar costs, while giving consideration to the administrative cost of time-differentiated rate structures. Where time-differentiated rates are employed, typical rate structures might be an on-peak and off-peak period, differentiated between a summer and winter season.

Two separate measures of marginal cost, long-run marginal cost and short-run marginal cost, can be employed in cost allocation studies. In economic terms, long-run marginal cost refers to the cost of serving a change in customer usage when all factors of production (i.e., capital facilities, fuel stock, personnel, etc.) can be varied to achieve least-cost production. Short-run marginal cost refers to the cost of serving a change in customer usage when some factors of production, usually capital facilities, are fixed. For example, if load rises unexpectedly, short-run marginal cost could be high as the utility seeks to meet this load with existing resources (i.e., the short-run perspective). Similarly, if a utility has surplus capacity, short-run marginal cost could be low, since capacity additions would provide relatively few benefits to the utility. When a utility system is optimally designed (utility facilities meet customer needs at lowest total cost), long-run and short-run marginal costs are equal.

A common source of confusion in marginal cost studies arises in considering the economic time frame of investment decisions. There is an incorrect tendency to equate long-run marginal cost with the economic life of new facilities, suggesting that long-run marginal cost has a multi-year character. In actuality, both short-run and long-run marginal costs are measured at a single point in time, such as a rate proceeding test year.[1]

There is considerable difference of opinion as to whether short-run or long-run marginal cost is appropriate for use in cost allocation. In competitive markets, prices tend to reflect short-run marginal costs, suggesting that this may be the appropriate basis for cost allocation. However, long-run marginal costs tend to be more stable and may send better price signals to customers making capital investment decisions than do short-run marginal costs.[2]

## I. MARGINAL ENERGY COSTS

Marginal energy cost refers to the change in costs of operating and maintaining the utility generating system in response to a change in customer usage. Marginal energy costs consist of incremental fuel or purchased power costs[3] and variable operation and maintenance expenses incurred to meet the change in customer usage. Fixed fuel costs associated with committing generating units to operation are also a component of marginal energy costs when a change in customer usage results in a change in unit commitment.[4]

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[1]In contrast, analysis of investment decisions properly requires a projection of short-run marginal cost over the economic life of the investment. Long-run marginal cost is sometimes used to estimate projected short-run marginal cost (ignoring factors such as productivity change which may cause long-run marginal cost to vary over time), which perhaps contributes to the mistaken views regarding the economic time frame of long-run marginal cost.

[2]See, for example, the discussion in A. E. Kahn, The Economics of Regulation: Principles and Institutions, 1970, particularly Volume 1, Chapter 3.

[3]Incremental fuel costs are sometimes referred to as system lambda costs.

[4]These fixed fuel costs are commonly associated with conventional fossil fuel units which are used to follow load variations. These units often require a lengthy start-up period where a fuel input is required to bring the units to operational status. The cost of this fuel input is referred to as start-up fuel expenses. Also, at low levels of generation output, average fuel costs exceed incremental fuel costs because there are certain "overhead" costs, such as frictional losses and thermal losses, which occur irrespective of the level of the level of generator output. These costs are sometimes referred to as "no-load" fuel costs since they are unrelated to the amount of load placed on the generating unit.

## A. Costing Methodologies

The predominant methodology for developing marginal energy costs is the use of a production costing model to simulate the effect of a change in customer usage on the utility system production costs. Typically, a utility will operate its lower production cost resources whenever possible, relying on units with the highest energy production costs only when production potential from lower-cost resources has been fully utilized. Thus, the energy production costs for the most expensive generating units on line are indicative of marginal energy costs. However, utility generating systems are frequently complex, with physical operating constraints, contractual obligations, and spinning reserve requirements, sometimes making it difficult in practice to easily determine how costs change in response to a change in usage. A detailed simulation model reflecting the important characteristics of a utility's generating system can be a very useful tool for making a reasonable determination of marginal energy costs.

An alternative to using a production costing model is to develop an estimate of marginal energy costs for an historical period and apply this historical result to a test year forecast period. For historical studies, marginal energy costs can be expressed in terms of an equivalent incremental energy rate (in BTU/KWH), which reflects aggregate system fuel use efficiency. Expressing marginal energy costs in these units nets out the effect of changing fuel prices on marginal energy costs [5]. The use of historical studies should be approached with caution, however, when there is a significant change in system configuration (e.g., addition of a large baseload generating station), or where there are sizable variations in hydro availability. In these instances, system efficiency may change sufficiently to render historical studies unreliable as the basis for a test year forecast.

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[5] The incremental energy rate, or IER, is conceptually similar to an incremental heat rate, but measures aggregate system efficiency rather than unit-specific efficiency. The IER is calculated by dividing marginal energy costs by the price of the fuel predominantely used in meeting a change in usage. When the price of this predominant fuel changes, marginal energy cost can be approximated as the fuel price (¢/BTU) times the IER (BTU/KWH).

## 1. Production Cost Modeling

There are numerous computer models suitable for performing a simulated utility dispatch and determining marginal energy costs that are commercially available[6]. These production cost models require a considerable degree of technical sophistication on the part of the user. In general, results are highly sensitive both to the structural description of the utility system contained in the input data and the actual values of the input data. Verification or "benchmarking" of model performance in measuring marginal energy costs is an important step which should be undertaken prior to relying on a model in regulatory proceedings.

Typically, production cost models produce an output report showing marginal energy costs by hour and month. These reported costs represent the incremental cost of changing the level of output from the most expensive generating unit on line to meet a small change in customer usage. However, these costs do not include the effect of temporal interdependencies which should be accounted for in marginal energy costs. For example, if a unit with a lengthy start-up cycle is started on Sunday evening to be available for a Monday afternoon peak, the costs of starting up the unit are properly ascribed to this Monday peak period.

The effect of such temporal interdependencies can be measured with a production cost model using the incremental-decremental load method. The production cost model is first run to establish a base case total production cost. Then, for each costing period, two additional model runs are performed, adjusting the input load profile upward and downward by a chosen amount. The change in total production cost per KWH change in load is calculated for both the incremental and decremental cases, and the results averaged to give marginal energy costs by costing period.

The results of a production cost model simulation for the utility case study are shown in Table 9-1. The analysis uses an incremental/decremental load method to account for fixed fuel expenses associated with the additional unit commitment needed to meet a change in load during on-peak and mid-peak periods. Off-peak marginal energy costs are derived directly from the production cost model's reported marginal energy costs, since changes in off-peak usage are not anticipated to affect unit commitment. and

[6]Comparing and contrasting the efficacy of different production costing models is a complex undertaking that will not be attempted in this manual. The "state-of-the-art" in production cost modeling is envolving rapidly, with existing models increasing in sophistication and new models being developed.

mid-peak periods. Off-peak marginal energy costs are derived directly from the production cost model's reported marginal energy costs, since changes in off-peak usage are not anticipated to affect unit commitment.

## TABLE 9-1

### MARGINAL ENERGY COST CALCULATION USING AN INCREMENTAL/DECREMENTAL LOAD METHODOLOGY

### (Based on a Gas Price of $2.70/MMBTU)

| | 500 MW Decrement | 500 MW Increment | Combined |
|---|---|---|---|
| Summer On-Peak | | | |
| Change in Production Cost ($) | -9,120 | +9,209 | 18,329 |
| Change in KWH Production (GWH) | -261 | +261 | 522 |
| Marginal Cost (¢/KWH) | | | 3.5 |
| In BTU/KWH | | | 12,993 |
| Summer Mid -Peak | | | |
| Change in Production Cost ($) | -9,613 | +9,631 | 19,244 |
| Change in KWH Production (GWH) | -393 | +393 | 786 |
| Marginal Cost (¢/KWH ) | | | 2.4 |
| In BTU/KWH | | | 9,089 |
| Summer Off-Peak | | | |
| Marginal Cost (¢/KWH ) | - | - | 2.2 |
| In BTU/KWH | | | 8,129 |
| Winter On-Peak | | | |
| Change in Production Cost ($) | -9,930 | +11,479 | 21,409 |
| Change in KWH Production (GWH) | -348 | +348 | 696 |
| Marginal Cost (¢/KWH ) | | | 3.1 |
| In BTU/KWH | | | 11,393 |
| Winter Mid-Peak | | | |
| Change in Production Cost ($) | -19,843 | +19,411 | 39,254 |
| Change in KWH Production (GWH) | -785 | +785 | 1,576 |
| Marginal Cost (/KWH) | | | 2.5 |
| In BTU/KWH | | | 9,260 |
| Winter Off-Peak | | | |
| Marginal Cost (¢/KWH ) | - | - | 2.4 |
| In BTU/KWH | | | 8,730 |

Note: These figures exclude variable operation and maintenance expenses of 0.3¢/KWH.

## 2. Historical Marginal Energy Costs

Where production cost model results are not available, use of historical data as a proxy to forecast future marginal energy costs may be considered. The starting point to estimating historical marginal energy costs is incremental fuel cost (system lambda) data. A number of adjustments to these system lambda costs may be necessary in order to properly calculate marginal energy costs. In low-load periods, production from baseload units or power purchases may be reduced below maximum output levels, while higher cost units are left in operation to respond to minute-to-minute changes in demand. In this instance, the cost of power from the baseload units or purchases with reduced output, not system lambda, represents marginal energy costs. Similarly, in a high-load period, the cost of power from on-line block-loaded peaking units would represent marginal energy cost, even though the cost of these units may not be reflected in the system lambda costs. In a system dominated by peaking hydro, but energy constrained, the cost of production from non-hydro units which serve to "fill the reservoir" represents marginal energy costs.

Another necessary adjustment would be to account for the fixed fuel costs associated with a change in unit commitment when there is a change in load. This fixed fuel cost can be estimated as follows. First, identify how an anticipated change in load affects production scheduling. For example, if production scheduling follows a weekly schedule, an increase in load might increase weekday unit commitment but not impact weekend operations. Second, identify what fraction of time different types of units would be next in line to be started or shut down in response to a change in load. Third, rely on engineering estimates to establish the fixed fuel costs for each type of unit. With this information, the fixed fuel cost adjustment can be estimated by taking the product of the probability of particular units being next in line times the fixed fuel cost for each unit. The fixed fuel cost can be allocated to time period by investigating how changes in load by costing period affect production scheduling. A simple approach would be to identify the probability of different costing periods being the peak, and using these probabilities to allocate fixed fuel costs to costing periods.

## B. Allocation of Costs to Customer Group

Marginal energy costs vary among customer groups as a result of differences in the amount of energy losses between generation level and the point in the transmission/distribution system where power is provided to the customer. Energy losses tend to increase as power is transformed to successively lower voltages, so energy losses (and thus marginal energy costs) are greatest for customer groups served at lower voltages. Ideally, energy losses should be time-differentiated and should reflect incremental losses associated with a change in customer usage, rather than average losses, although incremental losses are difficult to measure and are seldom available. Table 9-2 shows marginal energy costs by customer group, taking into account time-differentiated average energy losses for the utility case study. The variation in average marginal energy costs in Table 9-2 is due solely to differences in energy losses, reflecting differences in service voltage among the customer groups.

**TABLE 9-2**

**MARGINAL ENERGY COSTS
BY TIME PERIOD AND RETAIL CUSTOMER GROUP**

**(¢/KWH, at Sales Level)**

| | Summer | | | Winter | | |
|---|---|---|---|---|---|---|
| **Customer Group** | **On-Peak** | **Mid-Peak** | **Off-Peak** | **On-Peak** | **Mid-Peak** | **Off-Peak** |
| Residential | 4.18 | 3.00 | 2.70 | 3.68 | 3.05 | 2.86 |
| Commercial | 4.17 | 2.99 | 2.69 | 3.68 | 3.05 | 2.85 |
| Industrial | 4.08 | 2.94 | 2.64 | 3.57 | 2.96 | 2.80 |
| Agriculture | 4.18 | 3.00 | 2.70 | 3.68 | 3.05 | 2.86 |
| Street Lighting | 4.13 | 2.97 | 2.67 | 3.63 | 3.01 | 2.83 |

## II. MARGINAL CAPACITY COSTS

In most utility systems, generating facilities are added primarily to meet the reliability requirements of the utility's customers.[7] These generating facilities must be capable of meeting the demands on the system with enough reserves to meet unexpected outages for some units. System planners employ deterministic criteria such as reserve margin standards (e.g., 20 percent above the forecast peak demand) or probabilistic criteria such as loss of load probability (LOLP) standards (e.g., one outage occurrence in ten years). Whichever approach is used, these standards implicitly reflect how valuable reliability is to utility customers. Customers are willing to pay for reliable service because of the costs that they incur as a result of an outage. More generally, this is referred to as shortage cost, including the cost of mitigating measures taken by the customer in addition to the direct cost of outages. Reasonable reliability standards balance the cost of improving reliability (marginal capacity cost) with the value of this additional reliability to customers (shortage cost).

[7] In some systems that rely heavily on hydro facilities, energy may be a constraining variable rather than capacity. New generating facilities are added primarily to generate additional energy to conserve limited water supplies. In such circumstance, marginal capacity costs are essentially zero.

## A. Costing Methodologies

There are two methodologies in widespread use for determining marginal capacity costs, the peaker deferral method and the generation resource plan expansion method. The peaker deferral method uses the annual cost of a combustion or gas turbine peaker (or some other unit built solely for capacity) as the basis for marginal capacity cost. The generation resource plan expansion method starts with a "base case" generation resource plan, makes an incremental or decremental change in load, and investigates how costs change in response to the load change.

### 1. Peaker Deferral Method

Peakers are generating units that have relatively low capital cost and relatively high fuel costs and are generally run only a few hours per year. Since peakers are typically added in order to meet capacity requirements, peaker costs provide a measure of the cost of meeting additional capacity needs. If a utility installs a baseload unit to meet capacity requirements, the capital cost of the baseload unit can be viewed as including a reliability component equivalent to the capital cost of a peaker and an additional cost expended to lower operating costs. Thus, the peaker deferral method can be used even when a utility has no plans to add peakers to meet its reliability needs. The peaker deferral method measures long-run marginal cost, since it determines marginal capacity cost by adding new facilities to just meet an increase in load, without considering whether the existing utility system is optimally designed. The peaker deferral method compares the present worth cost of adding a peaker in the "test year" to the present worth cost of adding a peaker one year later. The difference is the annual (first-year) cost of the peaker. This cost is adjusted upward since, for reliability considerations, more than one MW of peaker capacity must be added for each MW of additional customer demand.[8] In the utility case study, the installed capital cost of the peaker is $615/KW, resulting in a marginal capital cost of $80/KW. Details on the derivation of this latter figure are provided in Appendix 9-A.

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[8]The peaker deferral method is described in greater detail in National Economic Research Associates, A Framework for Maginal Cost-Based Time-Differentiated Pricing in the United States: Topic 1.3, Electric Utility Rate Design Study, February 21, 1977.

## 2. Generation Resource Plan Expansion Method

An alterntive approach to developing marginal production cost is to take the utilion resource plan as a base case, and then increment or decrement the load forecast on which the plan was based. An alternate least-cost resource plan is then developed which account the modified load forecast. The resulting revision to the generation resource plan captures the effect of the change in customer usage.[9]

Similar to the peaker deferral method, the annual costs of the base case and revised generation resource plans are calculated, and then discounted to present-worth values. The annual revenue requirements include both capital-related and fuel-related costs, so fuel savings associated with high capital cost generating units are reflected in the analysis. The difference between the present-worth value of the two cases is the marginal capacity cost of the specified change in customer usage.

In the utility case study, the least-cost response to an increase in customer load in the "test year" would result in returning a currently retired generating unit to service one year sooner. The increase in total production cost (capital and fuel costs) associated with this increased load case results in a marginal capacity cost of $21/KW. The derivation of this figure is provided in Appendix 9-A. In contrast to the peaker deferral method, the generation resource plan expansion method measures short-run marginal cost, since it explicitly accounts for the current design of the utility system. In the utility case study, the presence of a temporarily out-of-service generating unit indicates surplus capacity, which accounts for the difference between short-run marginal capacity cost and long-run marginal capacity cost.

## B. Allocation to Time Period

LOLP refers to the likelihood that a generating system will be unable to serve some or all of the load at a particular moment in time due to outages of its generating units. LOLP tends to be greatest when customer usage is high. If LOLP in a period is 0.01, there is a one percent probability of being unable to serve some or all customer load. Similarly, if load increases by 100 KW in this period, on average, the utility will be unable to serve one KW of the additional load. Summing LOLP over all periods in a year gives a measure of how reliably the utility can serve additional load.

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[9] The generation resource plan expansion method is described in greater detail in C. J. Cicchetti, W. J. Gillen, and Paul Smolensky, The Marginal Cost and Pricing of Electricity: An Applied Approach, June 1976.

If load increases in an on-peak period when usage is already high, the LOLP-weighted load is high and there is a relatively large impact on reliability which must be offset by an increase in generating resources. If load increases in an off-peak period when usage is low, the LOLP-weighted load is low and there may be relatively little impact on reliability. Similarly, when additional generating resources are added to a utility system, the incremental reliability improvement in each period is proportional to the LOLP in that period. Thus, LOLP's can be used to allocate marginal capacity costs to time periods. A simple example showing the derivation of LOLP and its application to allocating marginal capacity costs to time periods is shown in Appendix 9-B.

An actual allocation of marginal capacity costs to time periods is shown in Table 9-3, based on the utility case study. The LOLP's are based on a probabilistic outage model that takes into account historical forced outage rates, scheduled unit maintenance, and the potential for emergency interconnection support.

**TABLE 9-3**

**ALLOCATION OF MARGINAL CAPACITY COST TO TIME PERIOD**

| Time Period | Hours | LOLP | Marginal Capacity Cost |
|---|---|---|---|
| Summer On-Peak | 12:00 noon - 6:00 p.m. | 0.716949 | $57.31 |
| Mid-Peak | 8:00 a.m. - 12:00 noon | | |
| | 6:00 p.m. - 11:00 p.m. | 0.124160 | 9.93 |
| Off-Peak | 11:00 p.m. - 8:00 a.m. | | |
| | and all weekend hours | 0.002532 | 0.20 |
| Winter On-Peak | 8:00 a.m. - 5:00 p.m. | 0.054633 | 4.37 |
| Mid-Peak | 5:00 p.m. - 9:00 p.m. | 0.087076 | 6.96 |
| Off-Peak | 9:00 p.m. - 8:00 a.m. | | |
| | and all weekend hours | 0.014650 | 1.17 |

## C. Allocating Costs to Customer Groups

Marginal capacity costs vary by customer group, reflecting differences in losses between generation level and the point where the power is provided to the customer (sales level). Ideally, the loss factors used to adjust from sales to generation level should reflect incremental losses rather than simply reflecting average energy losses, although incremental losses are difficult to measure and are seldom available.

Table 9-4 shows marginal capacity costs by rating period, reflecting losses by customer group, based on the utility case study. This table is constructed for illustration only, by assuming that each customer group's usage is constant for all hours within the rating periods shown. In actuality, the revenue allocation described in Chapter 11 uses hourly customer group loads and hourly LOLP data to calculate hourly marginal capacity costs by customer group.

### TABLE 9-4

**AVERAGE MARGINAL CAPACITY COSTS BY RATING PERIOD AND RETAIL CUSTOMER GROUP**

**($/KW month)**

| | Summer (4 Months) | | | Winter (8 Months) | | | |
|---|---|---|---|---|---|---|---|
| **Customer Group** | **On-Peak** | **Mid-Peak** | **Off-Peak** | **On-Peak** | **Mid-Peak** | **Off-Peak** | **Annual** |
| Residential | 15.86 | 2.74 | 0.06 | 0.60 | 0.96 | 0.16 | 88.32 |
| Commercial | 15.79 | 2.72 | 0.06 | 0.60 | 0.96 | 0.16 | 87.96 |
| Industrial | 15.46 | 2.67 | 0.06 | 0.59 | 0.94 | 0.16 | 86.12 |
| Agriculture | 15.86 | 2.74 | 0.06 | 0.60 | 0.96 | 0.16 | 88.32 |
| Street Lighting | 15.69 | 2.71 | 0.06 | 0.60 | 0.95 | 0.16 | 87.36 |

In general, all customers receive the same level of reliability from the generation system, since it is seldom practical to provide service at different reliability levels. Sometimes customers are served under interruptible tariffs or have installed load management devices, however, which effectively provide a lower reliability service. The marginal capacity cost for these customers may be zero if the utility does not plan for, or build, capacity to serve the incremental load of these customers. If the utility continues to plan for serving these customer loads, but with a lower level of reliability, the marginal capacity cost for these customers is related to the marginal capacity cost for regular customers by their relative LOLP's.

# APPENDIX 9-A

## DERIVATION OF MARGINAL CAPACITY COSTS USING THE PEAK DEFERRAL AND GENERATION RESOURCE PLAN EXPANSION METHODS

This appendix provides an example of the application of the peaker deferral method and the generation resource plan expansion method to calculating marginal capacity cost.

### A. Peaker Deferral Method

The peaker deferral method is described in greater detail in Topic 1.3 of the Electric Utility Rate Design Study, A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States (National Economic Research Associates, February 21, 1977). This method begins with a forecast of the capital and operating costs of a peaker.

Based on the capital and operating costs of a peaker, a future stream of annual revenue requirements is forecast over the expected life of the peaker and its future replacements. Next, this stream of annual revenue requirements is discounted to a single present-worth value using the utility cost of capital.[10] Next, the annual stream of revenue requirements is shifted forward assuming that construction of the peaker and its future replacements is deferred one year, and the resulting stream of revenue requirements is discounted to a single present-worth value. The difference between these two present-worth values is the deferral value -- the "cost" of operating a peaker for one year. Finally, this deferral value must be scaled upward to reflect that a peaker is not perfectly reliable, and may not always be available to meet peak demands. This can be done by comparing the reliability improvement provided by a "perfect" resource (one that is always available) to the reliability improvement provided by a peaker. This ratio, sometimes called a capacity response ratio (CRR), is then multiplied by the peaker deferral value to calculate marginal capacity cost.

[10] Arguably, a ratepayer discount rate may be more appropriate than the utility's cost of capital. Due to the difficulty of developing a ratepayer discount rate, utility cost of capital is commonly employed for discounting. The cost of capital should be based on the cost of acquiring new capital. This will generally differ from the authorized rate of return, which reflects the embedded cost of debt financing.

A calculation of marginal capacity cost using the peak deferral method is illustrated in Table 9A-1, based on the utility case study. The calculation starts with the installed capital cost of a combustion turbine, including interconnection and appurtenant facilities and capitalized financing costs, of $614.97/KW.

**TABLE 9A-1**

**DEVELOPMENT OF MARGINAL PRODUCTION COST USING THE PEAKER DEFERRAL METHOD**

| Line No. | Item | $/KW |
|---|---|---|
| 1 | Peaker Capital Cost | 614.97 |
| 2 | Deferral Value (Line (1) x 10.07%) | 61.93 |
| 3 | Operation and Maintenance Expense | 6.39 |
| 4 | Fuel Oil Inventory Carrying Cost | 1.19 |
| 5 | Subtotal (Line (2) + Line (3) + Line (4)) | 69.51 |
| 6 | Marginal Capacity Cost (Line (5) x 1.15) | 79.94 |

This initial capital investment (line 1) is then multiplied by an economic carrying charge of 10.07 percent to give the annual deferral value of the peaker (line 2). The economic carrying charge is conceptually similar to the levelized carrying charge which is frequently used in evaluating utility investments. While a levelized carrying charge produces costs which are level in nominal dollars over the life of an asset, the economic carrying charge produces costs which are level in inflation-adjusted dollars.[11] The economic carrying charge is the product of three components, as shown in the following equation:

Economic carrying charge = revenue requirement present-worth factor
x infinite series factor
x deferral value factor

The revenue requirement present-worth factor is calculated based on the initial capital investment as follows. A projection of annual revenue requirements associated with the $614.97/KW initial investment is made for the life of the investment. Included

[11]The development of the economic carrying charge in this section ignores the effect of technological obsolescence. The effect of incorporating technological obsolescence would be costs that decline over time (in inflation-adjusted dollars) at the rate of technological obsolescence (see Attachment C, "An Economic Concept of Annual Costs of Long-Lived Assets" in National Economic Research Associates, *op. cit.*).

in these annual revenue requirements are depreciation, return (using the cost of obtaining new capital), income taxes, property taxes, and other items which may be attributed to capital investment. These annual revenue requirements are then discounted using the utility's cost of capital, producing a result perhaps 30 to 40 percent above the initial capital cost, depending largely on the utility's debt-equity ratio and applicable tax rates. The ratio of the discounted revenue requirements to the initial capital investment is the revenue requirement present-worth factor.

The next component in the economic carrying charge calculation increases the discounted revenue requirements to reflect the discounted value of subsequent replacements. The simplest approach is to use an infinite series factor. Assuming that capital costs rise at an escalation rate i, that the utility cost of capital is r, and that peakers have a life of n years, the formula is as follows:

$$\text{Infinite Series Factor} = \frac{1}{1 - \left(\frac{1+i}{1+r}\right)^{n}}$$

The final component of the economic carrying charge is the deferral value factor. If the construction of the peaker is deferred by one year, each annual revenue requirement is discounted an additional year, but is increased due to escalation in the capital cost of the peaker and its replacements. The value of deferring construction of the peaker for one year is given by the difference between the discount rate and the inflation rate, expressed in original year dollars, as follows:

$$\text{Deferral Value Factor} = \frac{r-i}{1+r}$$

The next step in the calculation of marginal capacity cost is to add annual expenditures such as operation and maintenance expenses (line 3), and the cost of maintaining a fuel inventory (line 4). Finally, the subtotal of these expenses (line 5) is multiplied by a capacity response ratio, accounting for the reliability of the peaker compared with a perfect capacity resource, to give the marginal capacity cost (line 6).

The peaker deferral method produces a measure of long-run marginal cost, since it measures the cost of changing the utility's fixed assets in response to a change in demand, without taking into account a utility's existing capital investments.

Using a probabilistic outage model, loss of load probability (See Appendix 9-B) can be used to adjust long-run marginal costs developed from a peaker deferral method to reflect short-run marginal costs. This is accomplished by multiplying the marginal capacity cost from the peaker deferral method times the ratio of forecast LOLP to the LOLP planning standard. This can be seen in the following example. If the LOLP planning standard is 0.0002, then a 10,000 KW increase in demand will, on average, result in an expected 2 KW being unserved. Since this is the planning standard, the value to consumers of avoiding these 2 KW being unserved is just equal to the cost of adding an addiin demand will, on average, result in 1 KW being unserved. Adding an additional resource would benefit consumers, but only an expected 1 KW of unserved demand would be avoided. Thus, the benefit of avoiding the 1 KW of unserved load is one-half the cost of the additional resources necessary to serve this load. In this example, short-run marginal capacity cost is one-half the long-run marginal capacity cost.

## B. Generation Resource Plan Expansion Method

The generation resource plan expansion method is described in greater detail in The Marginal Cost and Pricing of Electricity: An Applied Approach (C. J. Cicchetti, W. J. Gillen, and Paul Smolensky, June 1976). This method begins with the utility's current least-cost resource plan, increments or decrements load in the "test year" by some amount, and revises the least-cost resource plan accordingly. The present-worth cost of the two resource plans, including both capital and fuel costs, are compared, and the difference represents the marginal capacity cost for the chosen load increment.

The generation resource plan expansion method can be illustrated using the utility case study. In this case study, the utility has adequate resources to serve loads and, in addition, has surplus oil/gas units which are expected to be refurbished and returned to service to meet future load requirements. If load were to increase above forecast, this would accelerate the refurbishment of these units. For example, if load increased 200 MW, the refurbishment and return to service of a 225 MW unit would be advanced one year. The cost of this refurbishment is about $30 million and would result in perhaps a 15-year life extension. For simplicity, the annual cost of accelerating the capacity requirement is computed using the same economic carrying charge approach as developed above for the deferral of a peaker as follows:[12]

$$\text{Annual Cost (\$/KW)} = \frac{\text{(Capital Cost) x (Economic Carrying Charge)}}{\text{(Load Increment)}}$$

$$= \frac{(\$30{,}000{,}000) \text{ x } (0.1407)}{(200{,}000 \text{ KW})}$$

$$= \$21/\text{KW}$$

[12]The economic carrying charge is actually higher since the 15-year life extension is shorter than the expected 30-year life of the peaker. It would be more precise to identify the replacement capacity for the refurnished unit in the resource plan when it is eventually retired after 15 years, and take into consideration the effect of acclerating the unit's return to service on this furture replacement.

This annual cost should be reduced by the annual benefit of any fuel savings resulting from the accelerated return to service of the unit. However, a production cost model analysis shows that there are virtually no fuel savings from returning the unit to service, since its operating costs are about the same as for the oil/gas units already in service.

In implementing this generation resource plan method, care must be taken to choose load increments that do not lead to lumpiness problems. If the load increment is small, there may not be an appreciable impact on the generation resource plan. On the other hand, a modest load change may be sufficient to tilt the scales toward a new generating resource plan, overstating the effect of the load change in general. One approach to dealing with potential lumpiness problems is to investigate a series of successive load increments, and then take an average of the marginal capacity costs determined for the successive increments.

Comparing this result with the peaker deferral method, the utility's short-run marginal capacity cost of $21/KW is about 26 percent of the long-run marginal capacity cost of $80/KW associated with meeting the capacity requirements by adding new generating facilities.

# APPENDIX 9-B

## A SIMPLE EXAMPLE OF THE DERIVATION OF LOSS OF LOAD PROBABILITIES

This appendix provides a simple example of how LOLP is developed and used to allocate marginal capacity costs to time periods. In the example shown in Table 9B-1, there are two time periods of equal length: an on-peak period where load is 250 MW and an off-peak period where load is 150 MW. The utility has four generating units totaling 600 MW, with various forced outage rates. Table 9B-1 calculates the probability of each combination of the four units being available. For example, there is a 0.0004 probability that all of the units are out of service simultaneously. Similarly, there is a 0.0324 probability that Units C and D are available (0.9 probability that each unit is available) while Units A and B are not available (0.1 probability that each unit is in a forced outage). Thus, there is a 0.0004 probability that the utility would be unable to serve any load, a 0.0076 probability that the utility would be unable to serve loads above 100 MW, a 0.0432 probability that the utility would be unable to service loads above 200 MW, and so forth. When load is 150 MW in the off-peak period, the utility will be unable to serve this load if all four units are not available, if only Unit C is available, or if only Unit D is available. The probability of these events occurring is 0.0076. Similarly, the probability of being unable to serve the 250 MW load in the on-peak period is 0.0432. The overall LOLP is 0.0508, with 85 percent of this LOLP resulting from the on-peak period. Thus, 85 percent of the marginal capacity costs are allocated to the on-peak period and 15 percent to the off-peak period.

## TABLE 9B-1
## LOSS OF LOAD PROBABILITY EXAMPLE

**Resources:**

| Size | Forced Outage Rate | Expected Availability |
|---|---|---|
| A: 200 MW | 20% | 80% |
| B: 200 MW | 20% | 80% |
| C: 100 MW | 10% | 90% |
| D: 100 MW | 10% | 90% |

**Probabilities:**

| Units | MW Available | Cumulative Available Probability | |
|---|---|---|---|
| None | 0 | (.2)(.2)(.1)(.1)=0.0004 | 0.0004 |
| C | 100 | (.2)(.2)(.9)(.1)=0.0036 | 0.0040 |
| D | 100 | (.2)(.2)(.1)(.9)=0.0036 | 0.0076 |
| A | 200 | (.8)(.2)(.1)(.1)=0.0016 | 0.0092 |
| B | 200 | (.2)(.8)(.1)(.1)=0.0016 | 0.0108 |
| C, D | 200 | (.2)(.2)(.9)(.9)=0.0324 | 0.0432 |
| A, C | 300 | (.8)(.2)(.9)(.1)=0.0144 | 0.0576 |
| A, D | 300 | (.8)(.2)(.1)(.9)=0.0144 | 0.0720 |
| B, C | 300 | (.2)(.8)(.9)(.1)=0.0144 | 0.0864 |
| B, D | 300 | (.2)(.8)(.1)(.9)=0.0144 | 0.1008 |
| A, B | 400 | (.8)(.8)(.1)(.1)=0.0064 | 0.1072 |
| A, C, D | 400 | (.8)(.2)(.9)(.9)=0.1296 | 0.2368 |
| B, C, D | 400 | (.2)(.8)(.9)(.9)=0.1296 | 0.3664 |
| A, B, C | 500 | (.8)(.8)(.9)(.1)=0.0576 | 0.4240 |
| A, B, D | 500 | (.8)(.8)(.1)(.9)=0.0576 | 0.4816 |
| A, B, C, D | 600 | (.8)(.8)(.9)(.9)=0.5184 | 1.0000 |

**Time Period Demand:**

| | | LOLP | |
|---|---|---|---|
| On-Peak | 250 MW | 0.0432 | 85% |
| Off-Peak | 150 MW | 0.0076 | 15% |
| | | 0.0508 | |

# CHAPTER 10

## MARGINAL TRANSMISSION, DISTRIBUTION AND CUSTOMER COSTS

In contrast to marginal production costing methodology, analysts have devoted little attention to developing methodologies for costing marginal transmission, distribution and customer costs. An early evaluation noted: "... the determination of marginal costs for these functions, and especially distribution and customer costs, is much more difficult and less precise than for power supply, and it is not clear that the benefits are sufficient to justify the effort."[1] The referenced study, therefore, used average embedded costs, because they were both more familiar to ratemakers and analysts, and a reasonable approximation to the marginal costs. It is still common for analysts to use some variation of a projected embedded methodology for these elements, rather than a strictly marginal approach. While marginal cost concepts have been applied to transmission and distribution for the purpose of investigating wheeling rates, little of this analysis has found its way into the cost studies performed for retail ratemaking. The basic research into marginal costing methodologies for transmission, distribution and customer costs for retail rates was done in connection with the 1979-1981 NARUC Electric Utility Rate Design Study and most current work and testimony still refer back to those results.

### I. TRANSMISSION

There are several basic approaches to the calculation of the marginal cost of transmission. However, the first step in any approach is the definition of the study period. Transmission investments are "lumpy" in that they usually occur in large amounts at intervals. Therefore, it is important to select a study horizon that is long enough to reflect the relationship between investments and load growth. To the extent that investments are related to load growth occurring outside the study period or there is

[1] J. W. Wilson, Report for the Rhode Island Division of Public Utilities, Public Utilities Commission and Governor's Energy Office (1978), pp. B-27-8.